RECHARGING AMERICA

The Construction Response to Rising Power Demand

A quantitative assessment of how planned U.S. power-generation buildout drives construction-market demand, 2025–2030



MOCA SYSTEMS, INC.

Brandon Michalski
Principal, Chief Economist
MSI Economics
MOCA Systems, Inc.

Created by
Brandon Michalski
Principal, Chief Economist
MOCA Systems, Inc.
Office: (850) 389 8128
Cell: (304) 280 9766

MOCA SYSTEMS, INC.

1. Executive Summary **05**

What this means by audience

2. The Demand Picture

2.1 Regional Demand Concentration

2.2 Peak Load Dynamics and Capacity Intensity

2.3 Regional Demand Drivers

2.4 Implied Construction Outlook

2.5 Announced Investment

- Data centers
- Manufacturing
- Decarbonization
- Announced versus active pipeline

3. The Binding Constraint: Supply and Execution **14**

3.1 Equipment Availability: The Primary Gate

- Backloaded supply response

3.2 Materials: Cost Pressure versus Throughput Limits

3.3 Reliability Constraints and Capacity Intensity

3.4 Interconnection Queues: The Primary Timing Filter

3.5 The Four-Condition Filter for Construction Starts

3.6 Regional Constraint Regimes

3.7 Capital Allocation Toward Execution Certainty

4. Construction Forecast **21**

4.1 Methodology

4.1.1 Translating capacity into construction categories

4.2 Aggregate Outlook: Capacity and Capital

4.3 Technology Contributions to the Build Cycle

- Solar: volume anchor with policy sensitivity
- Wind: transitional volume with rising cost pressure
- Natural gas: dispatchable backbone with rising cost and timing constraints
- Nuclear: minimal near-term volume, high strategic value

4.4 Replacement versus New-Build Demand

4.5 Technology Mix

4.6 Construction-Market Capital Cost

4.7 Labor, Material, and Equipment Decomposition

Created by
Brandon Michalski
Principal, Chief Economist
MOCA Systems, Inc.
Office: (850) 389 8128
Cell: (304) 280 9766

5. Policy and Capital Allocation **34**
5.1 Reallocation of Federal Financing
5.2 Offshore Wind as a Removed Category
5.3 Redefining Responsibility for Grid Investment
5.4 Capital Moving Up the Stack
5.5 Regulatory Structure and Market Design
6. Technology Pathways and Optionality **37**
6.1 Battery Storage: Near-Term Volume, Concentrated Execution Pressure
6.2 Hydrogen-Capable Turbines: Procurement Without Near-Term Expansion
6.3 Small Modular Reactors: Strategic Positioning Beyond the Window
6.4 Relief Pathways and Substitution
7. Implications and Outlook **40**
7.1 The 2026 Surge Is the Planning Horizon That Matters
7.2 Gas Becomes the Critical Dispatchable Addition After 2027
7.3 Outer-Year Volume Is Contingent, Not Committed
7.4 What to Watch
Appendix I: Methodology **42**
Methodological Structure of Capital Cost Roll-Up
Structural Interpretation



Section 1
Executive Summary

1. EXECUTIVE SUMMARY

U.S. electricity demand is entering its first sustained growth phase in two decades, and the response is a generation-construction buildout that increases active-construction spend, the dollars deployed on projects underway in each year, by roughly 50% from 2026 baseline to roughly $150 billion by 2030. The central finding of this report is that the constraint on that buildout is not demand; it is execution. Equipment lead times, interconnection queues, skilled-labor availability, and capital sequencing, not the size of the announced pipeline, will determine how much construction actually occurs and when. Demand is large, real, and highly concentrated. Announced data-center and advanced-manufacturing investment through 2030 totals roughly $1.66 trillion, and projected peak-load growth implies a capacity-driven construction ceiling near $161.5 billion. Three markets, ERCOT, PJM, and MISO, account for about 87% of national implied construction spend, with ERCOT alone representing nearly half. The same regions face the tightest competition for electrical labor, transformers, switchgear, and interconnection throughput in the 2026–2028 window. Supply is the binding constraint, and its timing is asymmetric.

Through 2027, the availability of a narrow set of critical components gates which projects can be built: large power transformers, high-voltage switchgear, and heavy-frame gas turbines. Manufacturers are expanding capacity, but most new output arrives 2028 and later. The result is a temporally segmented market: near-term construction is throughput-limited and dominated by pre-positioned projects, while deferred demand accumulates into the back half of the decade. Volume is delayed, not destroyed.

The technology mix reshapes who builds what. Solar anchors volume at roughly three-quarters of capacity additions and the lowest cost per MW. Natural gas is the only dispatchable source scaling materially and the only technology with rising per-MW cost, pulling later-decade demand toward combustion-turbine and civil work. Wind rebounds sharply in 2026 on repowering, but its outer-year path is now highly uncertain as the current administration delays installed and permitted projects, widening the forecast range. Nuclear contributes almost no near-term volume but carries strategic value as the only carbon-free source matching continuous data-center load.

Federal policy in early 2026 reweighted capital rather than expanding it. The Department of Energy redirected roughly $30 billion in clean-energy lending toward gas and nuclear, offshore wind was effectively removed from the near-term pipeline, and large-load developers began committing to fund their own grid infrastructure. Private capital has moved upstream into generation ownership to secure delivery certainty. None of these actions relieves the 2026–2027 equipment bottleneck.

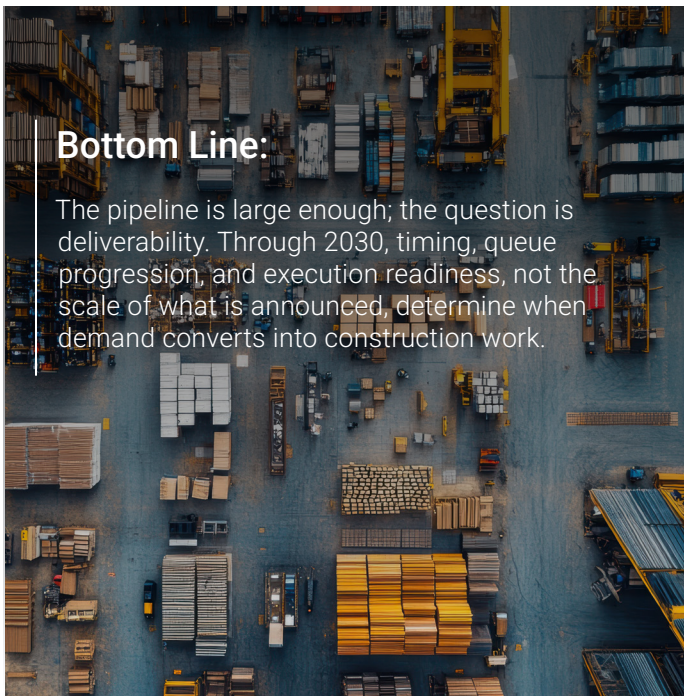
What this means by audience

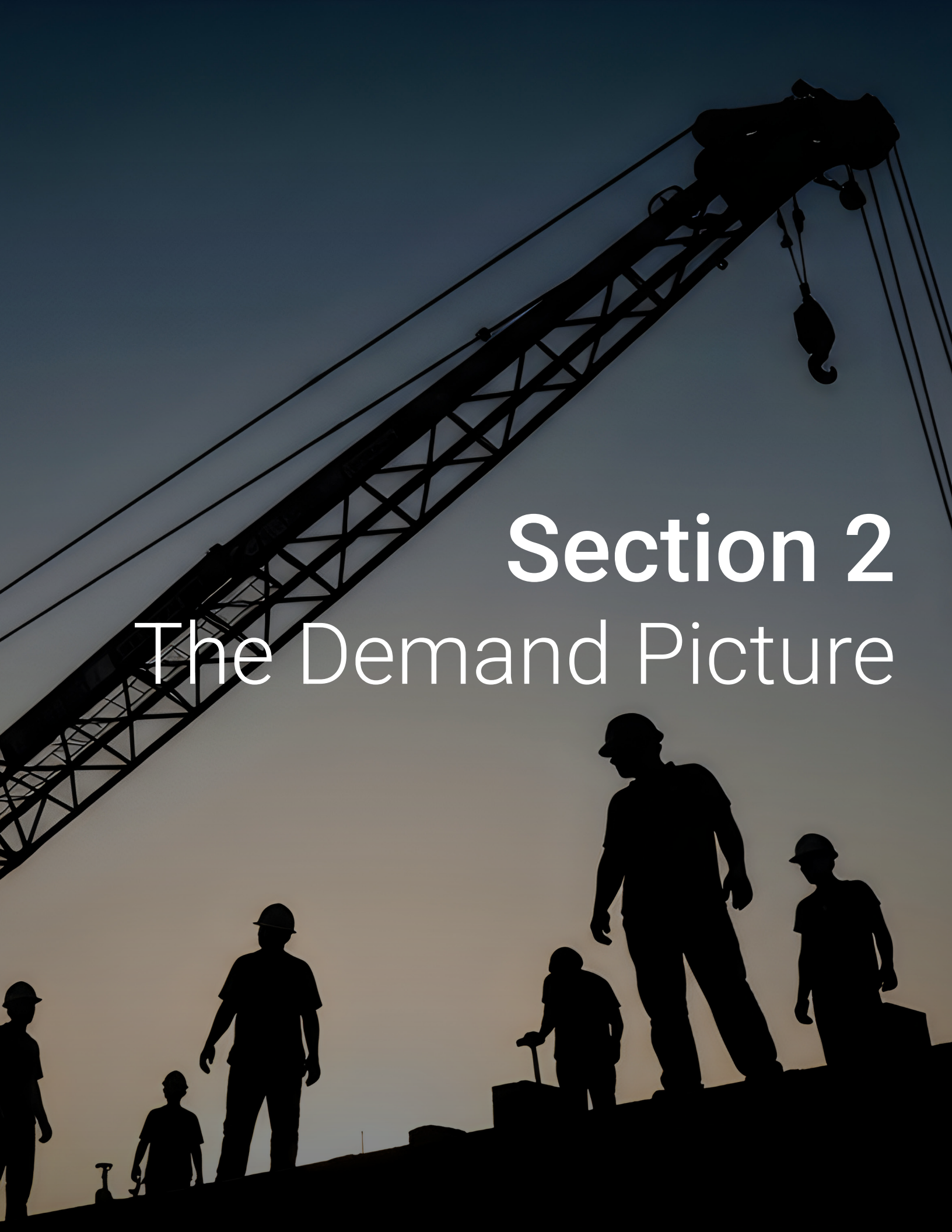
• **Contractors:** The prize is a generation-construction market that roughly doubles to about $150 billion a year by 2030, close to $691 billion cumulatively, about two-thirds of it material and permanent equipment and just under a third labor (see Sections 4.6–4.7). Backlog visibility and equipment procurement, not demand, set revenue timing, and firms built solely around the 2026 solar surge will face a composition mismatch as gas-related work grows after 2027.

• **Investors and capital allocators:** Capital is abundant and crowding in; execution capacity is the scarce asset. As private capital moves upstream into generation ownership to secure delivery certainty (see Section 5.4), returns accrue to those who control equipment slots, EPC capacity, and interconnection position, not to those who simply fund announced megawatts.

• **Owners and developers:** Execution readiness, not announced scale, determines which projects advance. Securing transformer and turbine slots early is now a precondition for hitting commissioning dates.

• **Policymakers:** This is an execution-capacity challenge, and the fastest way to convert demand into built capacity is to clear the execution path, accelerating interconnection queues, compressing permitting timelines, and removing the project-level delays that strand otherwise-ready megawatts (see Sections 3.4–3.5). Targeted support for domestic manufacturing throughput, supply-chain resilience, and workforce development relieves the remaining equipment and labor bottlenecks more effectively than broad financial incentives.





Section 2
The Demand Picture

U.S. electricity demand growth through 2030 is both concentrated and structurally uneven, with direct consequences for construction. Baseline load remains anchored in large legacy markets such as PJM, but incremental growth, and therefore marginal construction pressure, concentrates in ERCOT, PJM, and MISO. The distinction matters: construction demand is driven not by where load exists today, but by where it is expanding fastest under tightening system constraints.

2.1 REGIONAL DEMAND CONCENTRATION

ERCOT, PJM, and MISO together account for roughly 87% of national implied construction spend through 2030.

Figure 1: U.S. ISO/RTO Regions

Source(s): Federal Energy Regulatory Commission, RTOs and ISOs.

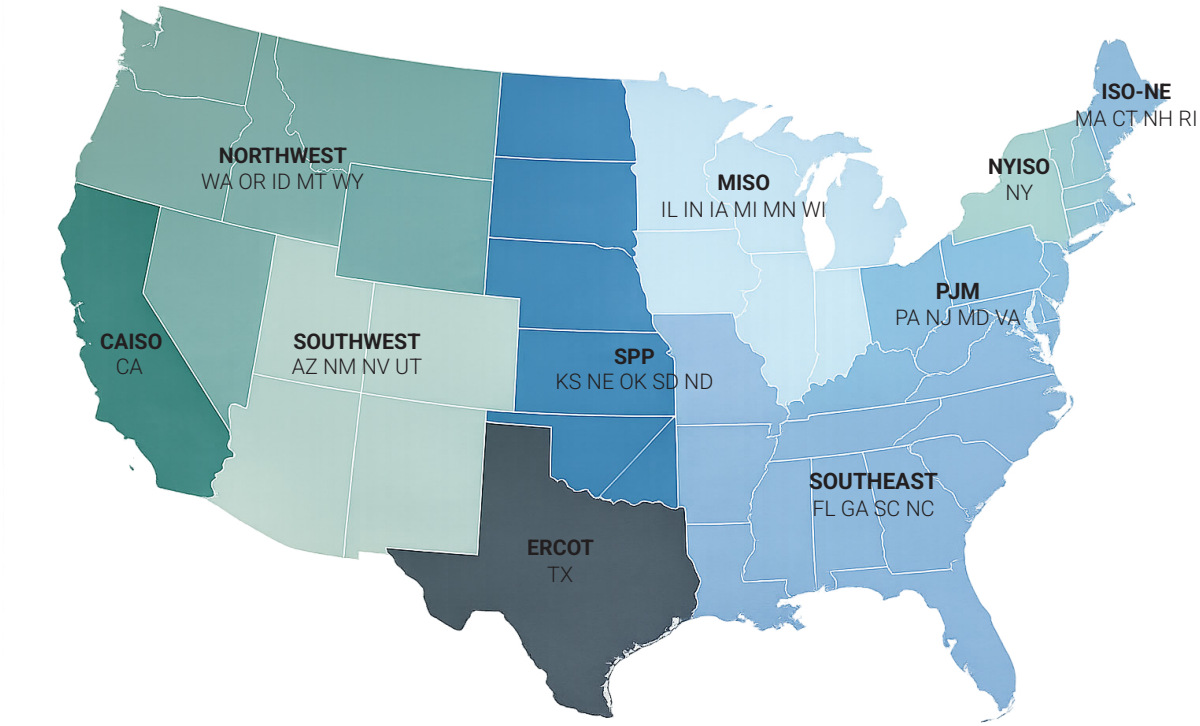


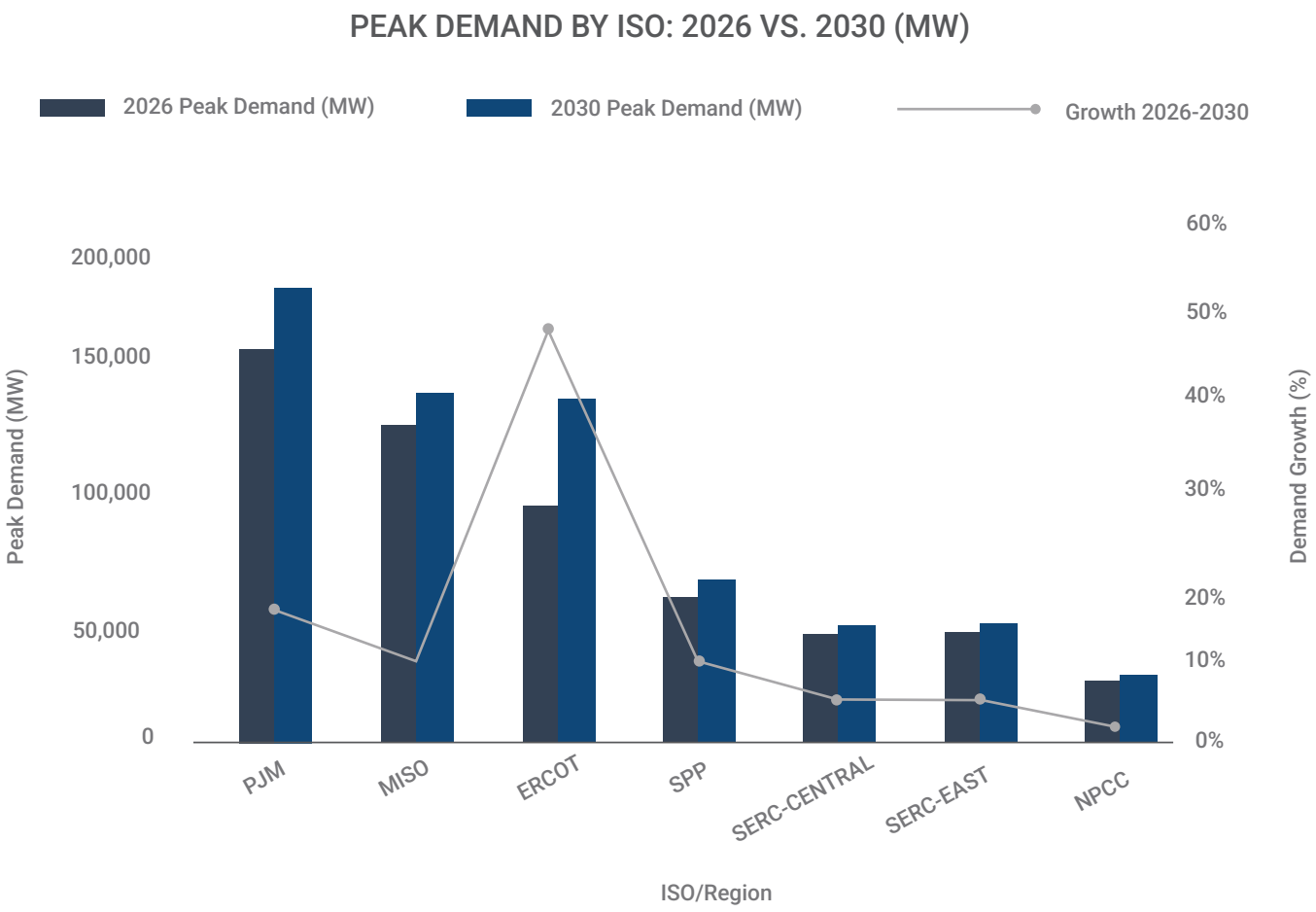
TABLE 1

REGIONAL PEAK DEMAND AND GROWTH BY ISO/RTO, 2026-2030

ISO/AREA	REGION	2026 PEAK (MW)	2030 PEAK (MW)	GROWTH (%)	PRIMARY DRIVER
PJM	Mid-Atlantic/ Ohio Valley	158,937	183,883	15.7%	Data centers, electrification
MISO	Upper Midwest/ Central	127,071	139,631	9.9%	Data centers (+18 GW by 2035), mfg
ERCOT	Texas	94,650	138,944	46.8%	Large loads (45 GW by 2030) 23 GW DC
SPP	Central Plains/ Southwest	57,479	64,475	12.2%	Industrial and population growth
SERC-CENTRAL	Southeast (AL, GA, MS, TN, KY)	43,066	45,280	5.1%	Mfg. resurgence, electrification
SERC-EAST	Southeast (VA, NC, SC, FL)	44,414	46,646	5.0%	Data centers, coal-retirement new build
NPCC	New England	24,877	25,557	2.7%	Electrification; gas-constrained

Source(s): NERC 2025 Long-Term Reliability Assessment.

Figure 2: U.S. ISO/RTO Regional Peak Demand Growth, 2026–2030



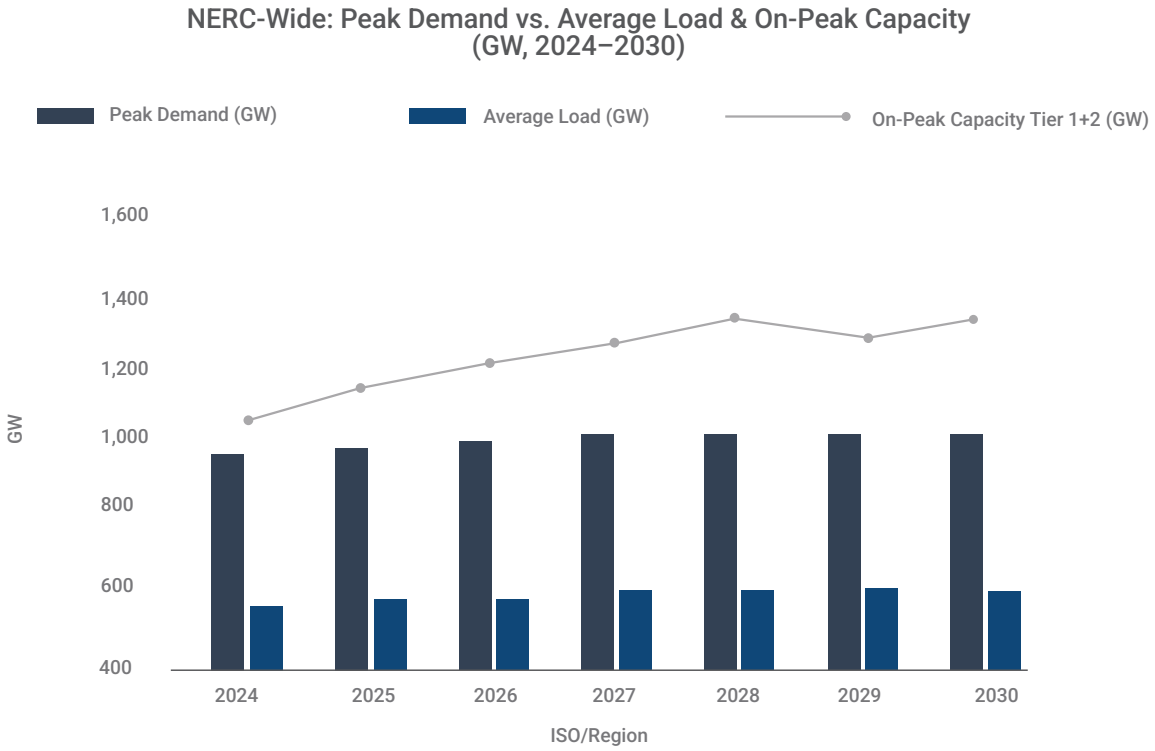
Source(s): NERC 2025 Long-Term Reliability Assessment

ERCOT's 46.8% growth rate is nearly three times PJM's and five times MISO's. Electrical craft labor, power transformers, switchgear, substation capacity, and interconnection throughput are all being drawn into these three geographies during the 2026–2028 window.

2.2 PEAK LOAD DYNAMICS AND CAPACITY INTENSITY

The gap between peak and average load widens by 41 GW between 2024 and 2030, compressing the national load factor from 61.9% in 2024 to a trough of 60.9% by 2027 before a partial recovery to 61.6% by 2030 as storage and demand response moderate extreme peaks. Load factor is average load as a share of peak demand; when it falls, each additional MW of peak requires more rated capacity to cover it, roughly 10 GW of additional peak-serving capacity on a 1,000 GW system at the trough, with no corresponding rise in energy output.

Figure 3: NERC-Wide: Peak Demand vs. Average Load and On-Peak Capacity (GW, 2024–2030)



Source(s): NERC 2024 Long-Term Reliability Assessment, Supplementary Data.

The practical effect is a shift in construction demand toward peaking generation, battery storage, substations, and switchgear rather than baseload generation through 2028. EPC firms and equipment suppliers calibrated to baseload demand are misreading the near-term cycle.

2.3 REGIONAL DEMAND DRIVERS

Data centers drive 2025–2026 load growth more than any other source. ERCOT reported 63 GW of large-load interconnection requests at year-end 2024, the majority tied to data centers[1]. Semiconductor fabs add load in MISO, SPP, and the Southeast. Electrification of vehicles and buildings contributes across all markets but does not lead growth in any high-growth region through 2030.

In Texas and the South Central and Southeast corridor, data centers, manufacturing, and population growth converge in the same transmission zones. High-voltage labor, transformers, substation capacity, and interconnection access are already constrained entering 2026; every additional load source compresses procurement lead times and pushes construction start dates later. New England is the outlier. Load growth is not the constraint; winter gas infrastructure is. Construction there targets resilience and fuel security rather than capacity expansion.

2.4 IMPLIED CONSTRUCTION OUTLOOK

Projected peak-load growth through 2030 implies a concentrated upper bound for generation-related construction. The framework applies each region's cumulative 2026–2030 incremental peak demand to the weighted-average construction cost of $1.72M per MW developed in Section 4[2]. It assumes all incremental demand is met with new-build capacity, with no adjustment for retirements, imports, demand response, storage, or efficiency. The $161.5B total is a capacity-driven ceiling, not a realizable forecast. Because the framework applies a single standardized national weighted-average cost to each region's ISO-level peak-demand growth, rather than committed EIA build volumes or region-specific pricing, this ceiling does not align precisely with the bottom-up technology forecast in Section 4.

Table 2: Implied Construction Spend by ISO/RTO, 2026–2030 ($B)

ISO/AREA	2026 PEAK (MW)	2030 PEAK (MW)	INCREMENTAL MW	INFERRED SPEND ($B)
PJM	158,937	183,883	24,946	$42.9
MISO	127,071	139,631	12,560	$21.6
ERCOT	94,650	138,944	44,294	$76.2
SPP	57,479	64,475	6,996	$12.0
SERC-CENTRAL	43,066	45,280	2,214	$3.8
SERC-EAST	44,414	46,646	2,232	$3.8
ISO-NE	24,877	25,557	680	$1.2
TOTAL	**550,494**	**644,416**	**93,922**	**$161.5**

Source(s): NERC 2024 LTRA; U.S. EIA Annual Energy Outlook 2026; MSI Economics.

ERCOT accounts for $76.2B of the $161.5B total, more incremental demand than PJM and MISO combined. The remaining four regions collectively account for about $21B, with no single market exceeding $4B. The ceiling is sensitive to conversion: if 25% of ERCOT's 44.3 GW of incremental load is delayed, imported, or offset by non-generation resources, roughly $19B of implied demand leaves the region. The $1.72M/MW national average also understates costs in gas-heavy markets such as ERCOT, where a region-specific adjustment would push implied spend higher.

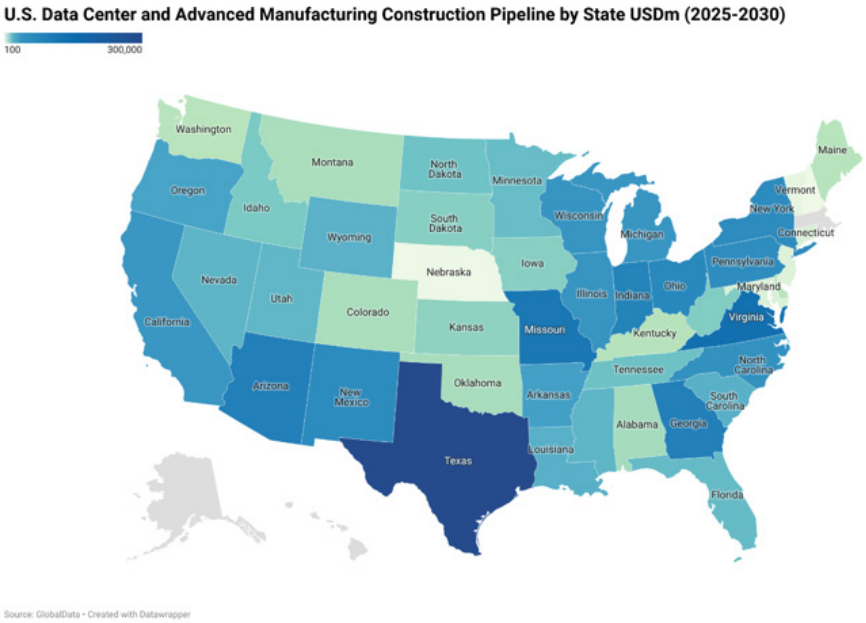
2.5 ANNOUNCED INVESTMENT

Announced investment in data centers and advanced manufacturing through 2030 totals roughly $1.66 trillion; about $1.25T in data centers and $403B in manufacturing. Texas leads both segments by dollar value, with a secondary tier across the Mid-Atlantic, Midwest, and Mountain West driven by semiconductor fabrication in Ohio, New York, and Oregon and data-center concentration in Northern Virginia and Arizona. These are announced project values, unadjusted for completion, a measure of developer intent and demand pressure, not a construction forecast.

SOURCE(S)

[01] ERCOT Board of Directors filing, December 2024, as reported in Latitude Media, February 2026.
[02] Weighted-average capital cost per MW ($1.72M) and technology-mix weights derived from the Section 4 probability-weighted pipeline model. See Section 4 methodology and MSI Economics model documentation.
[03] GlobalData, U.S. Construction Pipeline.
[04] GlobalData, U.S. Construction Pipeline (Power Generation).
[05] CHIPS and Science Act of 2022, Pub. L. No. 117-167, 136 Stat. 1366.

Figure 4: Announced Data Center and Manufacturing Investment by State, 2025–2030



Source(s): GlobalData (Data Center Construction).

DATA CENTERS

Announced data-center investment totals approximately $1.25T through 2030, about 76% of the combined pipeline[3]. Roughly 46% concentrates in four states: Texas ($244B), Virginia ($135B), Missouri ($113B), and Georgia ($88B). The 2025–2027 buildout window aligns with the national demand inflection, so electrical labor, transformer supply, and substation capacity face competing draws from data-center and generation construction in the same markets at the same time.

MANUFACTURING

Announced manufacturing investment totals $403B through 2030, about 24% of the pipeline[4]. Semiconductor fabrication accounts for $318B (79%), followed by assembly ($72B) and components ($13B). More than $36B in CHIPS Act awards had been finalized as of November 2025 across Intel, TSMC, Samsung, and Texas Instruments[5]; because federal disbursements are tied to construction milestones, semiconductor projects are more likely than data centers to start on schedule.

Roughly 72% of manufacturing investment concentrates in six states: Texas ($94B), Arizona ($65B), New York ($52B), Ohio ($32B), Indiana ($24B), and Oregon ($22B). Semiconductor spending is projected near $50B in 2029 and above $47B through 2030, sustaining demand for high-voltage labor, substation infrastructure, and transformer capacity after data-center construction peaks before 2027. Texas, Arizona, and Ohio face the longest period of elevated pressure across both segments.

DECARBONIZATION

Decarbonization affects construction through two channels: accelerated coal-plant retirement and incremental electrification load. Retirements are the more immediate force. Roughly 6.4 GW of coal capacity scheduled for retirement through 2026 required replacement contracting in 2024–2025, a window that is now largely closed[6]. Each retirement that clears before replacement capacity comes online tightens reserve margins and compresses the construction window. Electrification of vehicles and buildings is real but slower-moving and material mainly in California and the Northeast; through the forecast window, the retirement schedule drives more construction volume than incremental electrification. construction volume than incremental electrification.

SOURCE(S)

[06] U.S. Energy Information Administration, "Retirement delays of U.S. electric generating capacity may continue in 2026." Today in Energy, February 23, 2026.
[07] Sightline Climate, Data Center Outlook: Half of 2026 Pipeline May Not Materialize. February 24, 2026.

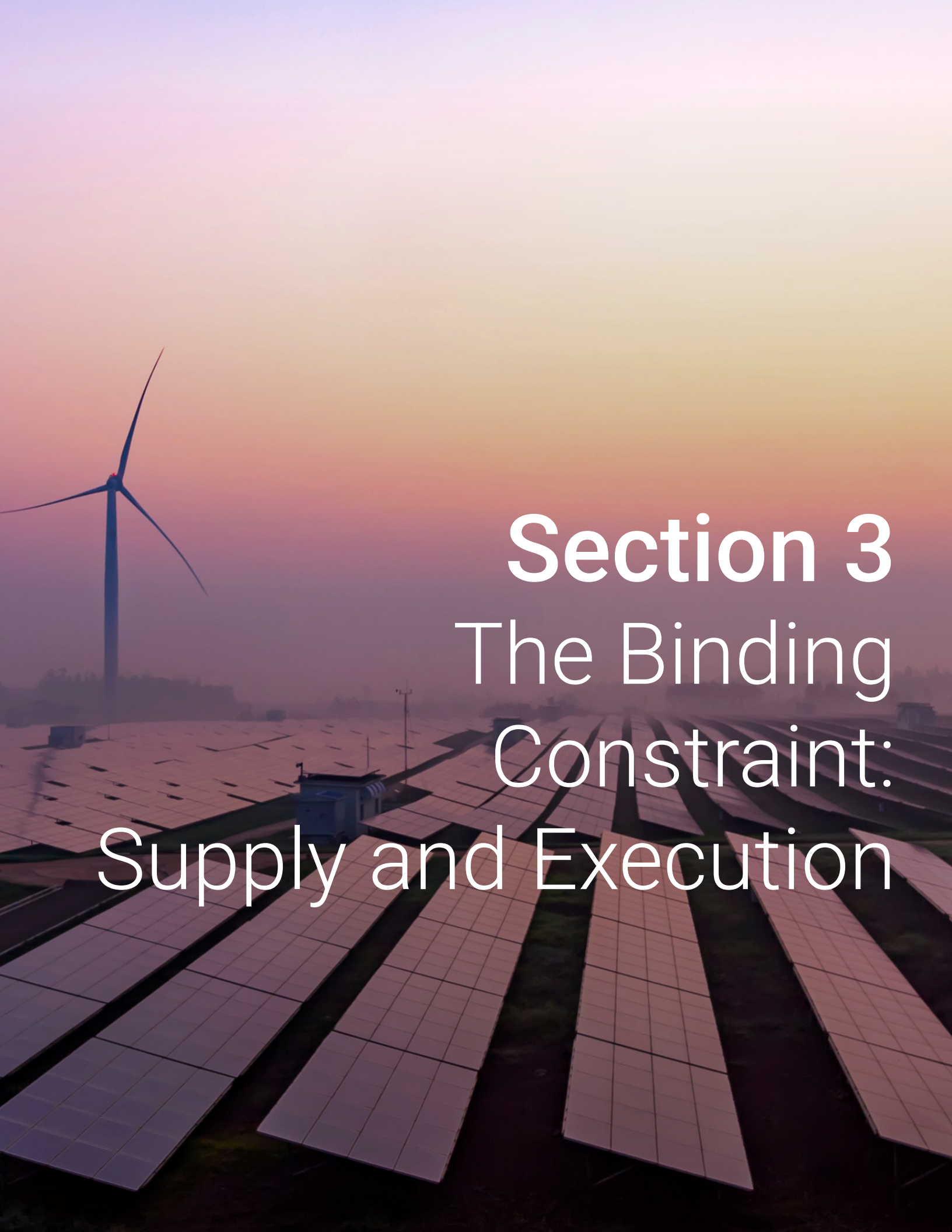
ANNOUNCED VERSUS ACTIVE PIPELINE

Headline pipeline figures overstate near-term executable volume. Sightline Climate estimates that 30–50% of capacity scheduled for 2026 delivery will be delayed, with 26% of expected 2025 capacity already deferred. Project cancellations rose from two in 2023 to six in 2024 and 25 in 2025, driven by power-access constraints and local opposition, and at least ten states have considered moratoria on new data-center development . Delays outpace outright cancellations, however: the $1.25T announced pipeline remains the relevant demand signal, and the primary effect to date is deferred construction starts rather than reduced total volume.



Discounting rule applied throughout this report:

announced capacity is treated as developer intent, not committed work. Translating these demand signals into construction volume requires discounting for completion probability, interconnection status, and equipment availability, the basis of the forecast in Section 4.



Section 3
The Binding Constraint: Supply and Execution

Supply conditions, not demand, govern the pace and sequencing of utility-scale power construction through most of the next decade. Equipment, materials, and capital are all characterized by extended lead times, concentrated manufacturing, and financing that prioritizes execution certainty over announced scale. The structural pattern is asymmetric in time: the constraint is binding through 2027 for projects that did not secure critical inputs in 2024–2025, and becomes manageable from 2028 onward as incremental supply comes online. This dynamic of volume deferred rather than destroyed shapes every section that follows.

3.1 EQUIPMENT AVAILABILITY: THE PRIMARY GATE

The most immediate constraint is the availability of a narrow set of critical components: large power transformers, high-voltage switchgear, and heavy-frame gas turbines. Procurement timelines now often exceed project-development cycles. Transformer lead times have expanded from a pre-2020 norm of 24–30 months to as much as 128 weeks for large units and 144 weeks for generator step-up transformers, with some specialized units taking even longer. Equipment procurement must now precede or run parallel to final investment decisions rather than follow them, a reversal of traditional sequencing that is most acute in data-center markets, where hyperscale operators target commissioning near 18 months.

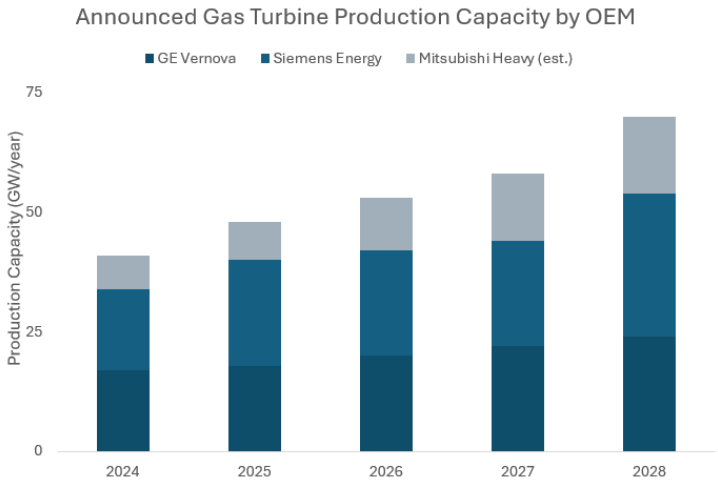
Domestic manufacturing limits reinforce the constraint. Grain-oriented electrical steel (GOES), a key transformer input, is produced by a single U.S. supplier, with roughly 80% of domestic demand met through imports[9]. North America also operates a limited fleet of specialized railcars for large transformers, with route-clearance requirements adding months. Incremental factory capacity therefore may not translate directly into near-term throughput.

Gas turbines present a parallel constraint. Heavy-frame combined-cycle units are quoted at five to seven years from order to commercial operation, while aeroderivative turbines offer 18–24-month lead times at roughly a 50% per-kW cost premium[10]. Despite lower operating efficiency, developers facing schedule pressure increasingly substitute toward aeroderivative units, paying a premium for delivery certainty. In combination, these factors make equipment procurement, not permitting or financing, the primary determinant of which projects advance in the near term.

Backloaded supply response

Manufacturers have responded with meaningful expansions, but their timing limits relevance for the current cycle. Across the three dominant turbine OEMs: GE Vernova, Siemens Energy, and Mitsubishi Heavy Industries, production guidance has been revised up sharply, with combined annual capacity projected to exceed 70 GW by 2028 and more than 200 GW cumulative through 2030 under conservative ramp assumptions[11].

Figure 5: Announced Gas Turbine Production Capacity by OEM, 2024–2028



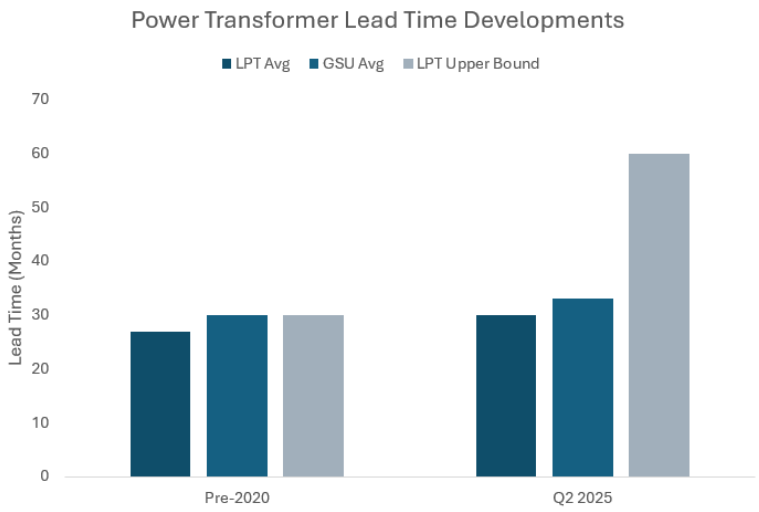
Source(s): Company investor presentations (GE Vernova, Dec 9, 2025; Siemens Energy CMD Nov 2025); Mitsubishi Heavy Industries (Bloomberg, Aug 31, 2025); Epoch AI, December 2025.

SOURCE(S)

[08] Wood Mackenzie, Q2 2025 Transformer Lead Time Survey, as reported in "Transformer Supply Chain Woes Persist as Energy Demand Grows," EE Power, August 2025.
[09] National Infrastructure Advisory Council, Addressing the Critical Shortage of Power Transformers to Ensure Reliability of the U.S. Grid. CISA, June 2024.
[10] S&P Global Commodity Insights research on aeroderivative gas turbine lead times, October 2025; Wood Mackenzie Q2 2025.
[11] GE Vernova investor presentation, December 9, 2025; Siemens Energy Capital Markets Day 2025, November 20, 2025; Mitsubishi Heavy Industries statement, August 31, 2025 (Bloomberg). Mitsubishi figures estimated. Epoch AI, December 2025.

Transformer manufacturing shows the same pattern. More than $2 billion in announced U.S. capacity expansions, including at Hitachi Energy, HD Hyundai, and Eaton, will modestly increase domestic supply, but most facilities are not operational until 2027–2028 or later[12]. Crucially, no corresponding expansion in GOES production has been announced, so upstream material constraints persist even as assembly capacity grows. Supply expansion is sufficient to relieve structural shortages over the medium term but does little for projects targeting delivery before 2028.

Figure 6: Power Transformer Lead Times, 2018–2025



Source(s): NIAC (June 2024); Wood Mackenzie Q2 2025 Transformer Lead Time Survey; Sightline Climate via Bloomberg (April 2026).

3.2 MATERIALS: COST PRESSURE VERSUS THROUGHPUT LIMITS

Material inputs affect construction through both cost escalation and physical supply limits, and the two are distinct. Broad commodity inflation in copper, steel, and concrete primarily affects economics: copper prices have risen roughly 70% since 2020, with added tariff pressure on imports, while GOES prices have roughly doubled over the same period . These increases raise per-MW capital costs but do not, in isolation, stop projects.

More consequential are low-elasticity inputs that act as bottlenecks regardless of price. Rhenium, used in high-temperature turbine blades, has risen roughly 280% since 2023 against global production of only about 62,000 kg annually , and its supply is linked to molybdenum and copper output, limiting responsiveness. Cobalt, critical to certain battery chemistries, is similarly concentrated, with more than 65% of global output from the Democratic Republic of Congo. The market is shifting toward lithium-ferro-phosphate (LFP) and novel iron-oxidation systems, which could ease the cobalt bottleneck, but those pathways remain nascent. Such inputs can delay production at critical nodes even when they do not halt expansion outright.

3.3 RELIABILITY CONSTRAINTS AND CAPACITY INTENSITY

Declining reserve margins and falling load factors push in the same direction: more nameplate capacity required per unit of demand, with less time to build it. As noted in Section 2, the compressing load factor alone implies roughly 10 GW of additional peak-serving capacity at the 2027 trough. Reserve margins compound the pressure.

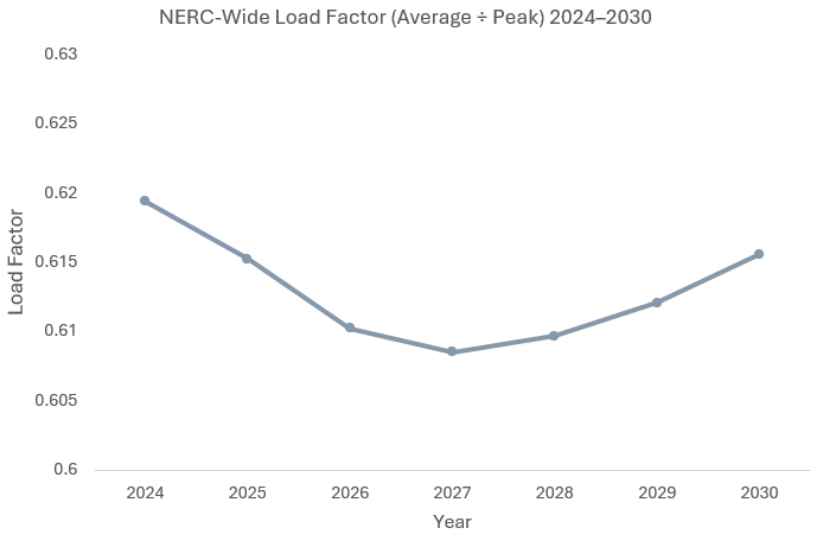
Table 3: Capacity Reserve Margin (%) by Region, 2024–2030

Region	2024	2025	2026	2027	2028	2029	2030
Eastern	15.3%	18.0%	18.5%	17.7%	16.8%	14.0%	12.1%
Texas (ERCOT)	12.3%	24.5%	28.5%	26.4%	22.6%	22.2%	21.5%
Western	26.7%	32.0%	28.9%	24.4%	23.3%	17.4%	16.0%
15% threshold	15%	15%	15%	15%	15%	15%	15%

Source(s): NERC 2025 Long-Term Reliability Assessment.

The Eastern Interconnection enters 2024 barely at the 15% planning threshold and falls to 12.1% by 2030. The Western Interconnection compresses faster in relative terms, from 26.7% to 16.0%, as retirements outpace replacement. ERCOT is the exception: starting below threshold at 12.3% in 2024, it recovers to 28.5% by 2026 on new investment and holds above 20% through 2030[15]. Committed capacity, or existing generation plus Tier 1 capacity under construction or contracted, falls from 145 GW in 2024 to 113 GW by 2030, leaving the system increasingly dependent on Tier 2 capacity that hinges on permitting, interconnection, and supply-chain execution.

Figure 7: National Load Factor and Reserve Margin Trends, 2024–2030



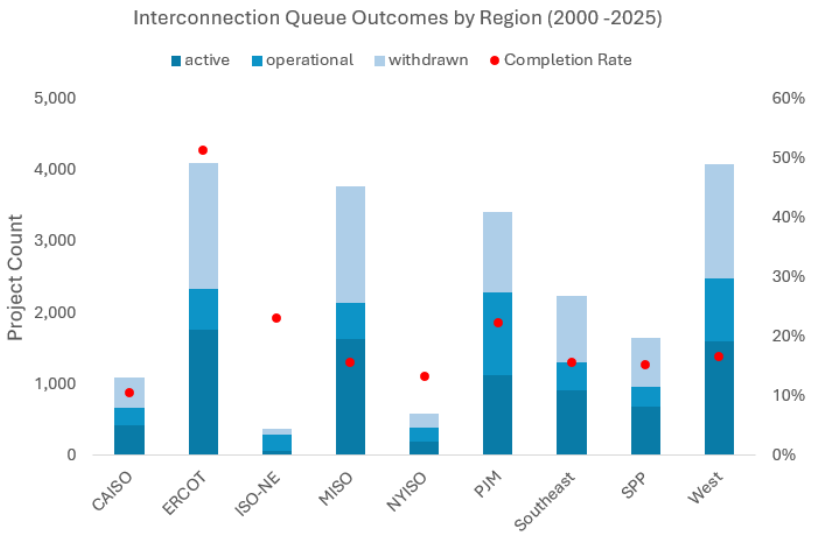
NERC 2024 Long-Term Reliability Assessment, Supplementary Data.

IMPLICATION:
Peak execution risk lands in 2026–2028, when peak-to-average divergence is widest, Tier 2 dependence is highest, and Eastern Interconnection margins are thinnest. In a system with shrinking buffers, delays in siting, procurement, or interconnection convert schedule risk directly into reliability risk.

3.4 INTERCONNECTION QUEUES: THE PRIMARY TIMING FILTER

The interconnection queue is the gap between announced capacity and construction starts. Queue volumes reflect developer intent, not committed backlog; projects must clear feasibility studies, network-upgrade cost exposure, and financing before execution[16].

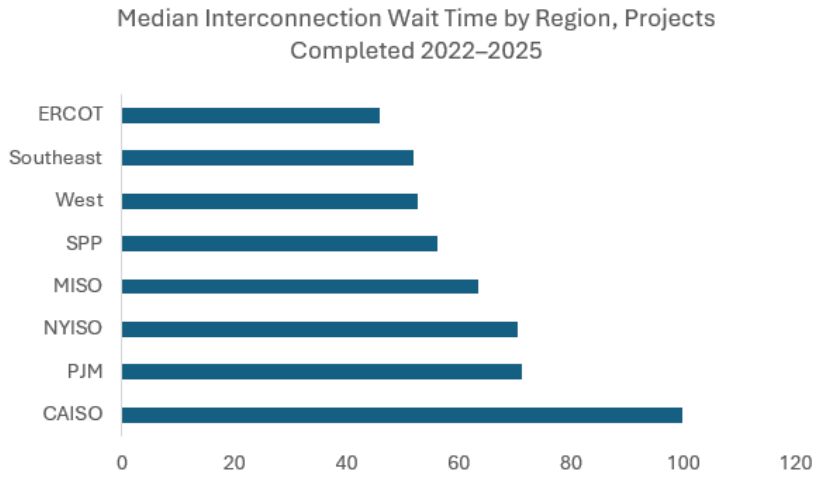
Figure 8: Interconnection Queue: Capacity Added, Withdrawn, and Completed by Region



Source(s): LBNL Queued Up 2025; MSI Economics.

Withdrawn project volume exceeds completed capacity in every major region, confirming high attrition. ERCOT posts the highest completion rate, reflecting faster study cycles and a less congested upgrade process than CAISO, PJM, or MISO, but everywhere else queue size is a poor proxy for construction potential.

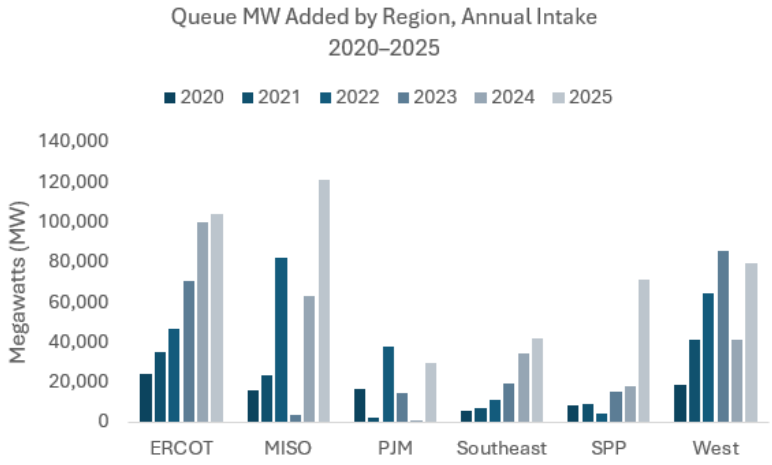
Figure 9: Median Interconnection Completion Timelines by Region (Months)



Source(s): LBNL Queued Up 2025; MSI Economics.

Median completion timelines range from 46 months in ERCOT to nearly 100 months in CAISO for projects entering service between 2022 and 2025. Projects entering queues in 2024–2025 will therefore support late-decade or early-2030s construction, not the 2026–2028 window. Near-term construction concentrates in projects that already hold advanced queue positions or executed interconnection agreements.

Figure 10: Annual Interconnection Queue Additions by Region (GW)



Source(s): LBNL Queued Up 2025; MSI Economics. Note: figures show MW added to the queue each year, not total active queue capacity.

Annual queue additions remain elevated across MISO, ERCOT, and Western markets, each adding tens of gigawatts per year. The volume reflects sustained developer demand but signals future pressure on studies, network upgrades, substations, and transformers rather than immediate construction starts. Queue maturity, not queue size, determines construction timing.

SOURCE(S)

[12] Hitachi Energy, South Boston, Virginia plant, September 2025 (Utility Dive, Sep 4, 2025); HD Hyundai Electric Alabama expansion (KED Global, Jan 2025; Transformer Magazine, 2026); Eaton $340M Jonesville, South Carolina expansion (Utility Dive, Feb 2025).
[13] Sightline Climate via Bloomberg, "US AI Data Center Expansion Relies on Chinese Electrical Equipment Imports," April 1, 2026.
[14] earthrarest.com/rhenium/price; accessed April 2026.
[15] NERC, 2025 Long-Term Reliability Assessment, January 29, 2026.

3.5 THE FOUR-CONDITION FILTER FOR CONSTRUCTION STARTS

Four conditions determine whether a project moves from pipeline to construction in the 2026–2027 window:

- **Cleared or advanced interconnection queue position**
- **Executed interconnection agreement**
- **Reserved equipment: transformers, turbines, switchgear**
- **Committed financing**

Projects meeting all four constitute the credible near-term construction universe; those missing any one, particularly equipment reservations, face 2028 or later start dates. Empirically, few projects clear the bar: of the 12–16 GW of data-center-related capacity projected for 2026 delivery, only about 5 GW is currently under construction, with roughly half of delays attributed directly to transformer and switchgear shortages.

Behind-the-meter generation can bypass portions of the interconnection process but still faces the same equipment lead times. The Federal Energy Regulatory Commission's rejection of the Amazon–Talen co-location proposal at Susquehanna confirmed that bypass models carry unresolved regulatory risk. Interconnection and equipment availability are hard schedule gates, not administrative steps.

3.6 REGIONAL CONSTRAINT REGIMES

Construction constraints are regional, not national. Queue timing, equipment access, weather exposure, and fuel reliability vary sharply by market and do not move with national demand trends.

Table 4: Regional Construction Constraint Matrix, 2026–2030

Region	Peak Load Growth	Queue / Timing Risk	Weather / Climate Risk	Fuel / Reliability Risk	Construction Pressure
ERCOT	High	Medium	High	High	High
PJM	High	High	Medium	High	High
MISO	Medium	High	Medium	Medium	High
CAISO / West	Medium	High	High	Medium	High
Southeast	Medium	Medium	High	Medium	High
ISO-NE	Low	Medium	High	High	Medium

Source(s): Qualitative synthesis of queue analysis, load-growth outlook, and regional reliability constraints (Sections 2–3).

• **ERCOT and PJM:** execution-capacity constraints. Demand is not the limit; execution is. ERCOT processes interconnections quickly, but solar, storage, gas, transmission, and substation projects compete for the same labor and equipment against 5%+ annual load growth. PJM's constraint concentrates in Northern Virginia, where data-center density requires generation, substation, and transmission investment in the same geography and window. In both, a cleared interconnection agreement does not move a project if the transformer slot is not reserved.

• **MISO:** replacement and transmission coupling. The $21.8B Long-Range Transmission Planning Tranche 2.1 program (3,631 miles, predominantly 765 kV, approved December 2024) draws on the same high-voltage equipment and labor as the generation it is meant to support[17]. Retirements already outpace firm replacement; concurrent transmission construction extends the constraint.

• **CAISO and the West:** queue duration and migration. CAISO averages nearly 100 months from request to operation, the longest in the dataset. Developers are siting in Arizona, Nevada, and New Mexico for faster study processes[18]; demand shifts west but does not accelerate, as the same equipment and labor constraints follow the pipeline.

• **Southeast:** process variability. Interconnection runs through individual utilities rather than a standardized ISO process, making schedule confidence project-specific. A project in a high-growth Southeast market can move faster than an ISO equivalent or stall entirely, depending on the utility.

• **New England:** fuel rather than queue constraints. The binding limit is fuel deliverability: interstate gas pipelines cannot serve heating and generation demand during sustained cold events, a physical limitation with no near-term fix[19]. Construction targets reliability hardening and fuel security.

3.7 CAPITAL ALLOCATION TOWARD EXECUTION CERTAINTY

Capital is increasingly allocated not to the largest nominal capacity but to projects that can secure power delivery within constrained infrastructure. Private capital has moved upstream into generation: large investors such as Blackstone and Brookfield are integrating generation ownership with end-use demand, while hyperscale firms secure 15–20-year power purchase agreements (PPAs) to guarantee supply. Those PPAs provide the revenue certainty to underwrite equipment orders, transmission upgrades, and substation construction but their delivery profiles are typically backloaded, with major nuclear-linked agreements not reaching full output until the early 2030s[20]. The result is a bifurcation between financing visibility and physical delivery: capital is committed, but the infrastructure to convert it into operational capacity remains constrained near-term. (The federal-policy dimension of this shift is treated in Section 5.)

SECTION CONCLUSION:

Energy-system constraints convert a large and growing pipeline into a sequenced, capacity-limited construction cycle. Through 2027, throughput remains below underlying demand and activity is dominated by a small cohort of pre-positioned projects; from 2028, expanded manufacturing and accumulated demand support a broader release of work. The implication is not a lack of work but a misalignment between demand and deliverability: timing, not total scale, determines realized activity.



SOURCE(S)

[16] Rand et al., Queued Up: 2025 Edition, Characteristics of Power Plants Seeking Transmission Interconnection. Lawrence Berkeley National Laboratory, 2025.
[17] MISO, Long-Range Transmission Planning, Tranche 2.1, approved by MISO Board of Directors, December 2024.
[18] California ISO, 2024–2025 Transmission Plan, approved May 2025.
[19] NERC, 2026 Summer Reliability Assessment, May 2026.
[20] Meta corporate release on nuclear agreements, January 9, 2026; Vistra Corp 8-K filing, January 2026.

Section 4
Construction Forecast

This section translates power-sector capacity expansion into construction-market demand. The methodology is summarized first, then results are presented in aggregate, by technology, and decomposed into construction-cost categories. All dollar figures are in 2025 nominal millions unless noted.

4.1 METHODOLOGY

MSI Economics focuses narrowly on generation-asset buildout; plant construction plus immediate grid interconnection (≤1 mile), across the four technologies that represent roughly 80% of expected additions by both capacity and capital: advanced natural gas (CCGT with carbon capture), solar PV, onshore wind, and advanced nuclear including SMRs. Long-distance transmission and distribution upgrades are treated as secondary effects to isolate generation-driven demand.

Core estimation. At the project level, construction value is the product of nameplate capacity, completion probability, and capital cost per MW, distributed across each project's build schedule:

$$\text{Construction Spend}_i = MW_i \times P_i \times C_i$$

WHERE:

- MW_i= Nameplate capacity of project *i*
- P_i= Probability of completion (function of technology + development stage)
- C_i= Capital cost per MW (technology-specific)

To align expenditure with construction activity over time, spend is distributed across each project's build schedule:

$$\text{Annual Spend}_t = \sum_{i=1}^{n} \frac{MW_i \times P_i \times C_i}{D_i}$$

WHERE:

- D_i= Construction duration (years) for project *i*
- Spend is allocated evenly unless otherwise specified by technology phasing assumptions

Completion probabilities (P_i) are derived from an empirically grounded matrix:

$$P_i = f(\text{Technology}_i, \text{Stage}_i)$$

This function is calibrated using:

- LBNL Queued Up 2025 (historical queue conversion rates)
- EIA Form 860M (active construction and completion tracking)

This step is critical in converting headline pipeline MW into executable capacity, systematically discounting early-stage or speculative projects.

Throughout, spend is attributed to the baseline year in which construction is active (2026): historical figures represent dollars spent on projects under construction in that year, not the value of work completed in earlier periods, and forecast years represent dollars still to be spent. The result is an active-construction measure that understates the full market in any year and should be read as a floor on activity rather than a total.

Forward growth. Beyond the observable pipeline, additions are extended using a blended growth rate that balances top-down EIA macro projections against bottom-up GlobalData pipeline formation, then adjusted for construction delays, equipment lead-time elongation, and capital availability:

$$MW_t = MW_{t-1} \times \left(\frac{g_{EIA} + g_{pipeline}}{2}\right)$$

This section translates power-sector capacity expansion into construction-market demand. The methodology is summarized first, then results are presented in aggregate, by technology, and decomposed into construction-cost categories. All dollar figures are in 2025 nominal millions unless noted.

WHERE:

- MW_t = MW in forecast year
- g_{EIA}= Capacity growth implied by EIA AEO2026
- $g_{pipeline}$= Observed GlobalData pipeline replenishment rate

Divergence between the two inputs (EIA & GlobalData) grows in the outer years (2028–2030), where pipeline visibility declines.

Capital weighting. Per-MW costs are anchored to EIA benchmarks, trended forward using a blend of Lazard's 2025 LCOE framework and observed GlobalData project costs, and adjusted for real-time frictions (equipment, labor, permitting). System cost is a capacity-weighted average across technologies:

Formally, forward capital costs are expressed as:

$$C_{t,k} = C_{0,k} \times (1 + g_{trend,k})^t \times (1 + \alpha_{constraint,t,k})$$

WHERE:

- $C_{t,k}$= Capital cost per MW for technology *k* in year *t*
- $C_{0,k}$= Baseline cost per MW (EIA-derived)
- $g_{trend,k}$= Underlying cost trend (blended from Lazard LCOE and GlobalData observations)
- $\alpha_{constraint,t,k}$= Adjustment factor capturing market frictions (equipment constraints, labor availability, permitting delays, and supply chain pressure)

To reflect changing technology mix over time, total system cost is calculated as a weighted average:

$$C_t^{weighted} = \sum_{k=1}^{K} s_{t,k} \times C_{t,k}$$

WHERE:

- $s_{t,k}$= Share of total capacity additions by technology *k* in year *t*

4.1.1 TRANSLATING CAPACITY INTO CONSTRUCTION CATEGORIES

Two complementary frameworks map the capacity forecast into construction-market impacts. Each technology is represented by a standardized configuration: natural gas as a 400 MW advanced CCGT, nuclear as a ~2,200 MW reactor proxy for SMR analogues, wind as a 100 MW onshore installation, and solar as a blended case (75% standalone PV, 25% PV-plus-storage).

Capital-cost method. Total project cost is decomposed into standard EPC components, allowing generation investment to map directly to contractor scope. The hierarchy builds up from direct construction inputs to total project value, with financing excluded throughout to isolate construction-relevant capital:

$$\underbrace{C_{civil} + C_{mechanical} + C_{electrical} + C_{indirect}}_{\text{EPC}_{pre}} \rightarrow \underbrace{\text{EPC}_{pre} + \text{contingency} + \text{fee}}_{\text{Total EPC}} \rightarrow \underbrace{\text{Total EPC} + \text{owner costs}}_{\text{Total Project Cost}}$$

Cost shares are benchmarked to the EIA's Updated Capital Cost Estimates for Utility-Scale Generating Plants[21] and escalated from a 2013 to a 2025 baseline using the Turner Construction Cost Index (a 71.9% increase). Component percentages are held constant across technologies to preserve structural consistency; the EPC layers, not owner costs, drive labor and equipment demand. A more thorough step-by-step methodology is described in the appendix.

SOURCE(S)

[21] U.S. Energy Information Administration, Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies. Prepared by Sargent & Lundy for AEO2025. February 2025.

Cost shares are benchmarked to the EIA's Updated Capital Cost Estimates for Utility-Scale Generating Plants and escalated from a 2013 to a 2025 baseline using the Turner Construction Cost Index (a 71.9% increase). Component percentages are held constant across technologies to preserve structural consistency; the EPC layers, not owner costs, drive labor and equipment demand. A more thorough step-by-step methodology is described in the appendix.

Labor–Material–Equipment (LME) method. EPC cost net of project indirects is reclassified into labor (29.0%), material (67.5%), and equipment (3.5%), where material is any capital equipment remaining on-site (turbines, concrete, structural steel, cable), and equipment is construction machinery that does not (cranes, excavators). Where the capital-cost method defines what is built, the LME method identifies what resources are required to build it and is used to evaluate supply-chain and labor pressure under constrained conditions.

$$\text{EPC Cost - Project Indirects} = L + M + E$$

WHERE:

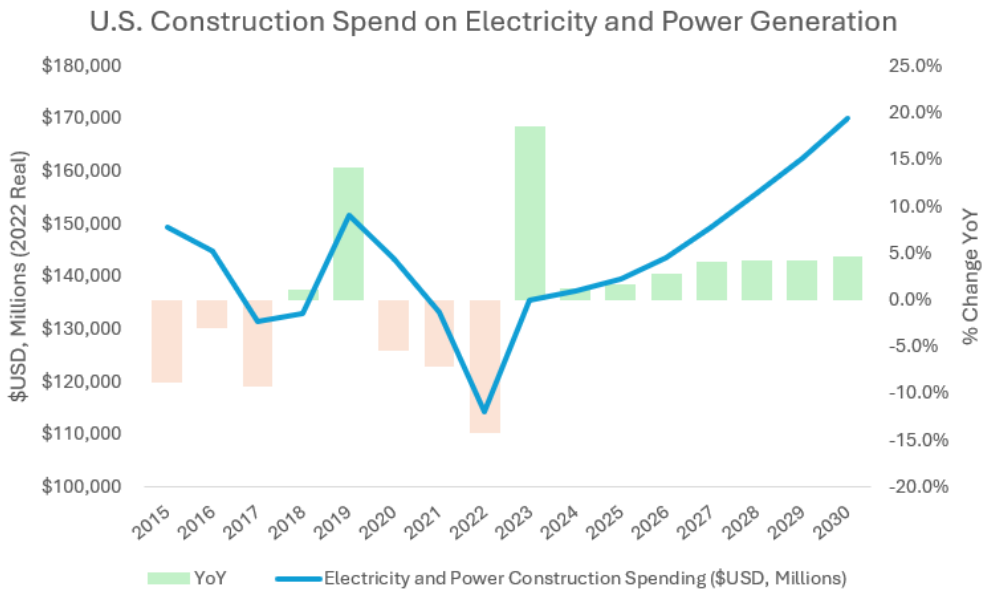
- L= Labor; 29.0% of total construction cost
- M= Material; any capital equipment that remains on-site such as turbines, concrete, structural steel, and electrical cables; 67.5% of total construction cost
- E= Equipment; any construction equipment that is utilized to build the project, but does not remain on-site after construction such as cranes, excavators, and dump trucks; 3.5% of total construction cost

4.2 AGGREGATE OUTLOOK: CAPACITY AND CAPITAL

Annual capacity additions according to EIA rise sharply in 2026, roughly 40% above 2025, and stay elevated through the decade. By 2029 the market runs at about twice the 2024 installation rate, with no staged ramp to absorb the increase. Total construction spend follows, rising from roughly $70 billion in 2025 to roughly $150 billion by 2030, slightly more than a doubling over the period, because rising per-MW costs for gas and wind offset solar's declining cost per MW so spend keeps pace with capacity.

Reading the EIA–GlobalData spread. Throughout this section, the EIA Annual Energy Outlook 2026 trajectory represents a deliverable baseline grounded in historical build rates, while the GlobalData pipeline defines the logic behind MSI Economics' upper bound that includes earlier-stage projects not yet cleared through interconnection, permitting, or financing. The gap between them, roughly 35 GW and about $61 billion annually by 2030, is a delivery-risk spread, not a demand difference. Treat it as possible upside, not committed work.

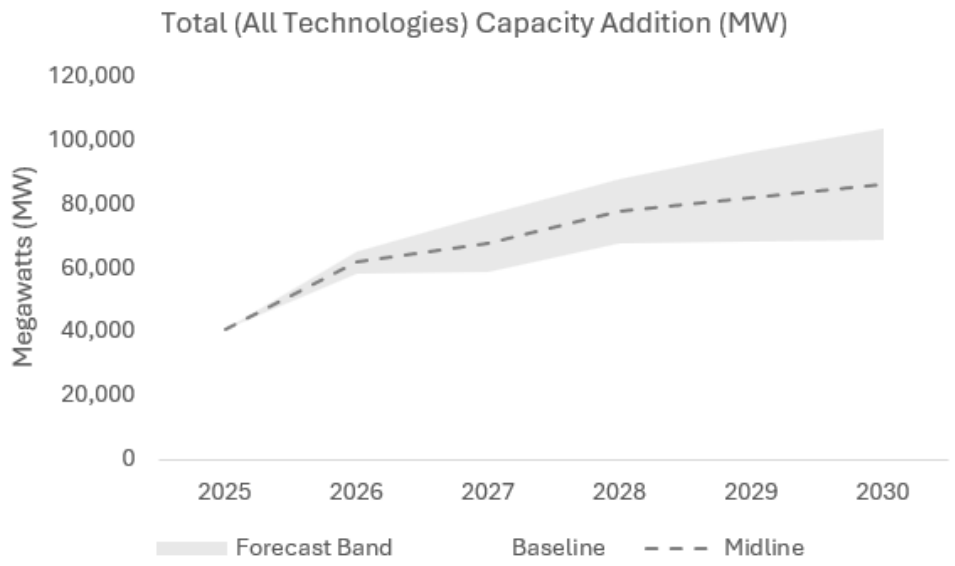
Figure 11: U.S. Construction Spend on Electricity and Power Generation, 2015–2030 ($USD, millions)



Source(s): GlobalData

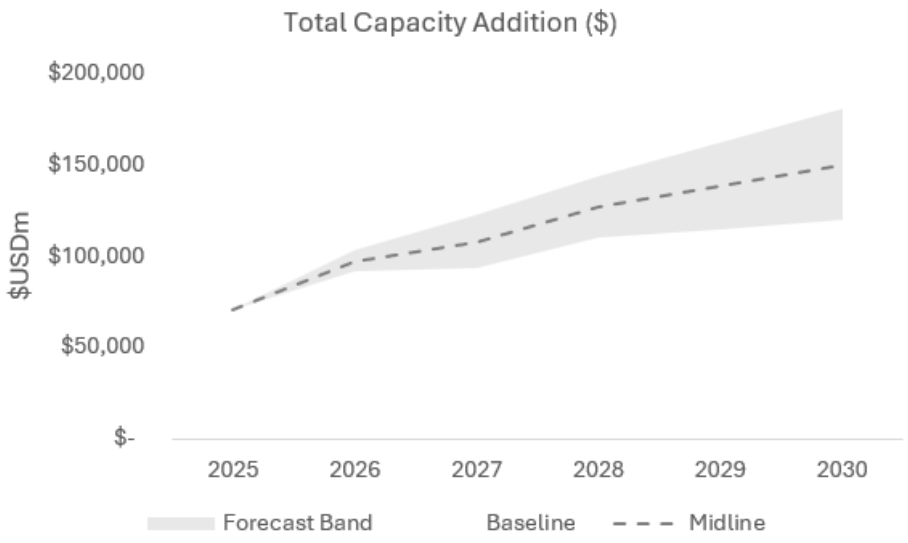
Figure 11 contextualizes the forecast against GlobalData's independent estimate of U.S. construction spending on electricity and power generation, which encompasses all components, including infrastructure and transmission. This reference is provided for directional context only: it illustrates the broader market's anticipated growth trajectory but does not reflect the specific parameters or scope of this study.

Figure 12: Total Generation Capacity Additions: MSI Forecast, 2025–2030 (MW)



Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

Figure 13: Total Generation Construction Spend: MSI Forecast, 2025–2030 ($B)



Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

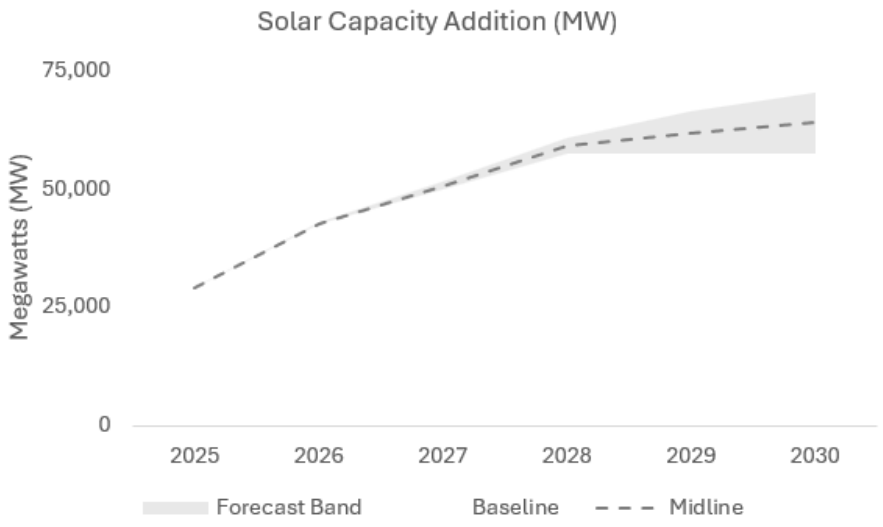
Weighted-average capital cost per MW stays relatively stable, masking divergence beneath: solar costs decline modestly, gas and wind rise on mix and supply-chain pressure, and nuclear remains several multiples above the rest. By 2030 the spread between highest- and lowest-cost technologies is wide enough that regional project composition, not national averages, determines realized construction cost. This capital outlook is not demand-constrained; EPC capacity, interconnection throughput, and equipment supply determine how much converts into realized activity.

4.3 TECHNOLOGY CONTRIBUTIONS TO THE BUILD CYCLE

Solar: volume anchor with policy sensitivity

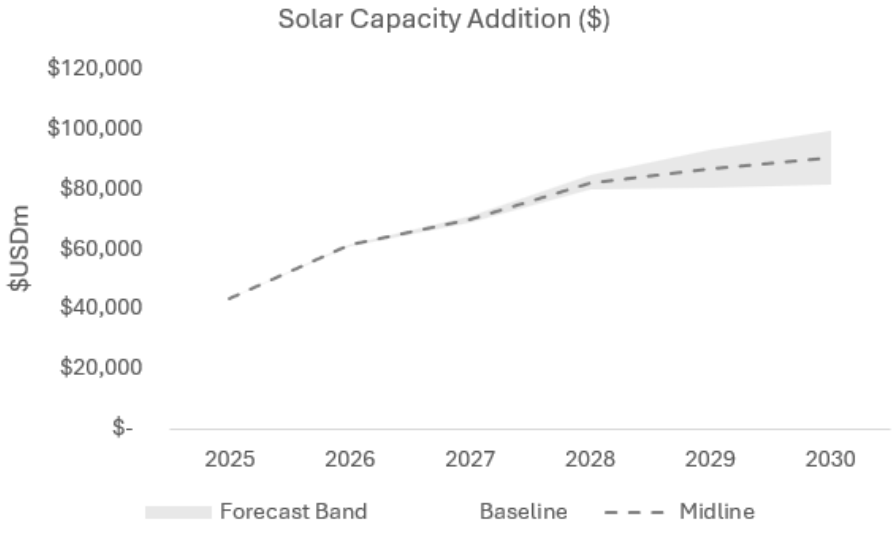
Solar holds about 74% of midline capacity additions across the period. Near-term volume through 2026 is the most confirmed in the dataset, with both sources tracking within 1%, but 2025 is a down year, not a plateau, a queue- and permit-driven contraction in which MW and spend fall together before the 2026 surge[22]. EPC firms pricing against a flat 2025 assumption are using the wrong entry point.

Figure 14: Solar Capacity Additions: MSI Forecast, 2025–2030 (MW)



Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

Figure 15: Solar Construction Spend: MSI Forecast, 2025–2030 ($USD, millions)



Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

SOURCE(S)

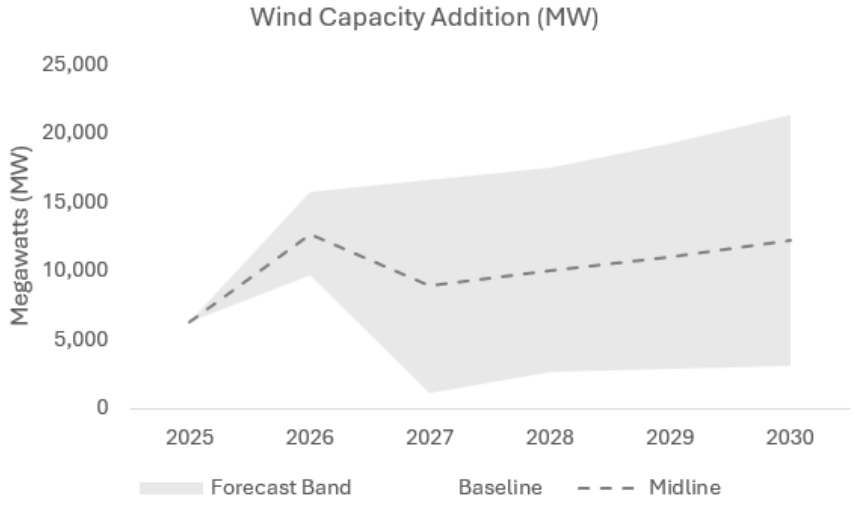
[22] Rand et al., Queued Up: 2025 Edition. Lawrence Berkeley National Laboratory, 2025.

Per-MW costs decline over the period; spend more than doubles from 2025 to 2030 because volume grows faster than costs fall. The roughly $18B EIA-to-GlobalData gap by 2030 reflects projects that have not cleared interconnection or financing. Outer-year volume above the EIA floor is contingent: the One Big Beautiful Bill Act (Pub. L. No. 119-21) eliminates solar and wind tax-credit eligibility for projects not beginning construction by July 4, 2026, and any project without a confirmed interconnection position by late 2025 is unlikely to meet that deadline.

Wind: transitional volume with rising cost pressure

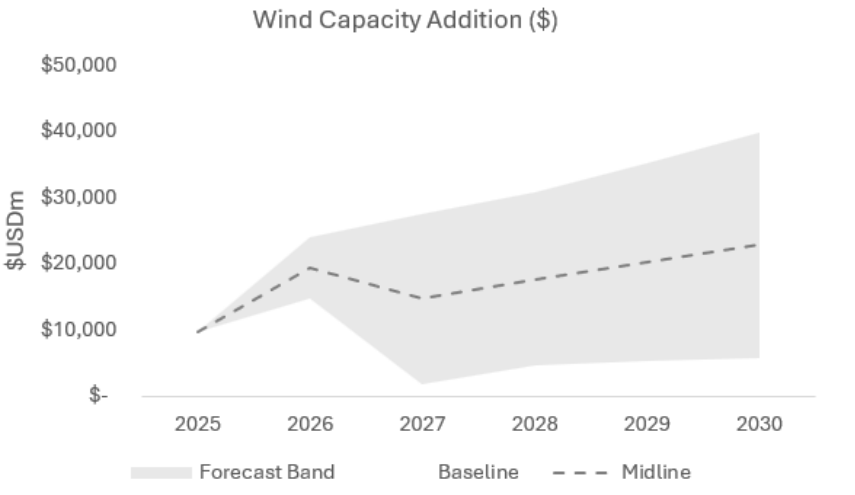
Wind additions roughly double in 2026, combining onshore repowering and new-build returning after supply-chain disruptions stalled activity through 2024[23]. Near-term wind is most confirmed in 2026; beyond that the forecast band widens sharply. The pre-2012 onshore fleet drives the 2026 surge; as those projects clear, outer-year volume becomes highly uncertain: installed and permitted projects face delays under the current administration, so the EIA baseline collapses to roughly 1,100 MW in 2027 and about 3,100 MW by 2030 while the high band stays near 21,300 MW, an unusually wide delivery-risk spread of about 18,000 MW by 2030 around a midline near 12,200 MW.

Figure 16: Wind Capacity Additions: MSI Forecast, 2025–2030 (MW)



Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

Figure 17: Wind Construction Spend: MSI Forecast, 2025–2030 ($USD, millions)



Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

SOURCE(S)

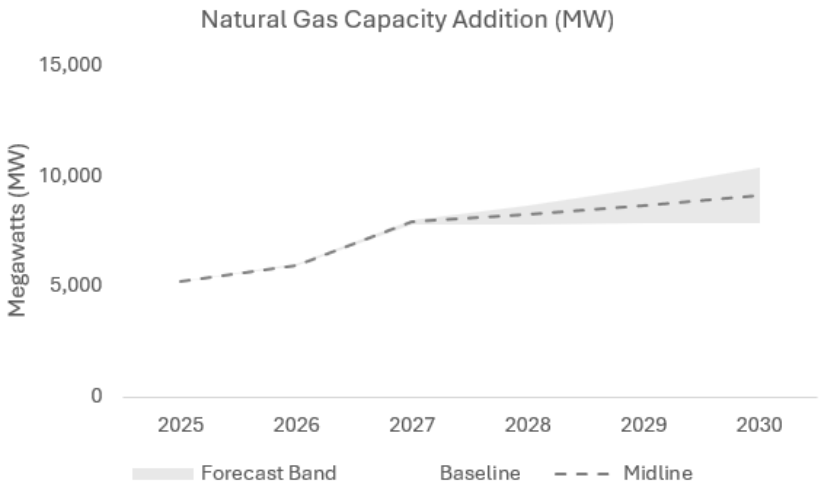
[23] Wiser, Ryan H., et al. Land-Based Wind Market Report: 2024 Edition. Lawrence Berkeley National Laboratory, August 2024.

Spend rises from $9.8B in 2025 to about $22.8B by 2030 at the midline, with a wide range of roughly $5.8B to $39.8B that reflects the installation-timing uncertainty. Wind is the only non-gas technology with rising per-MW costs, up 21% from 2026 to 2030, as repowering gives way to new-build on more complex sites. The same July 4, 2026 construction-start deadline applies, exposing projects that have not begun construction to credit-termination risk.

Natural gas: dispatchable backbone with rising cost and timing constraints

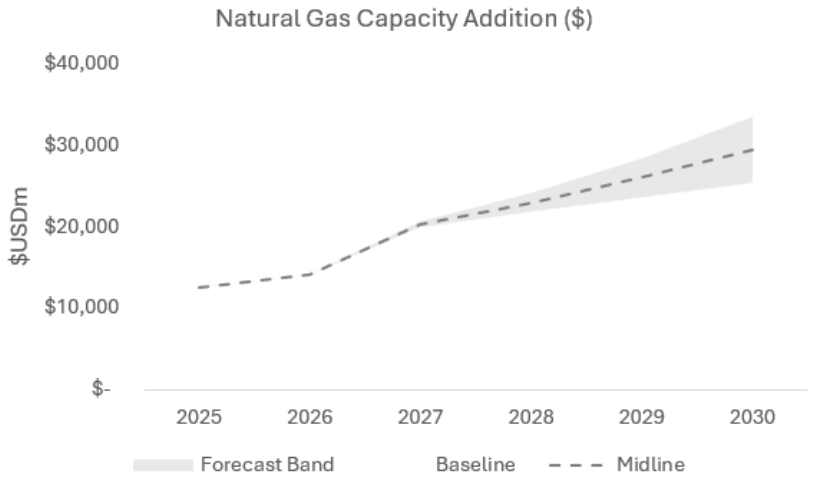
Gas is the only technology adding dispatchable capacity at scale. New-build collapsed to roughly 2,600 MW in 2024; midline additions recover to about 9,100 MW by 2030. Both sources track identically through 2026; the gap opens after 2027 and reaches about 2,500 MW by 2030, reflecting early-stage projects that have not cleared permitting, financing, or equipment procurement. Coal retirements through 2026 require firm replacement, and gas is the dispatchable backstop as coal exits.

Figure 18: Natural Gas Capacity Additions: MSI Forecast, 2025–2030 (MW)



Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

Figure 19: Natural Gas Construction Spend: MSI Forecast, 2025–2030 ($USD, millions)



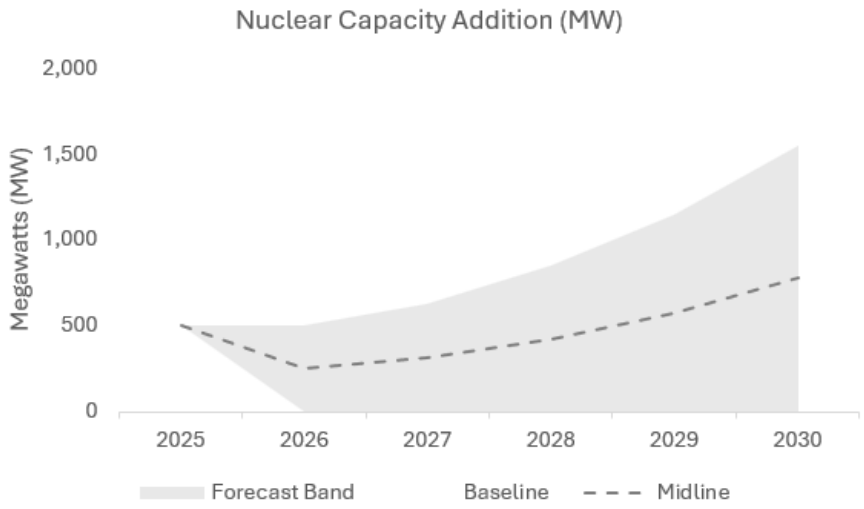
Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

Gas is the only technology with rising per-MW costs throughout (up roughly 28% since 2022). The pipeline skews toward peaking units that run only during high-demand hours; these cost more per MW than combined-cycle baseload and generate less output per dollar. By 2030 gas costs more than twice as much per MW as solar, and spend more than doubles from 2025, with the EIA-to-GlobalData gap reaching roughly $8B annually.

Nuclear: minimal near-term volume, high strategic value

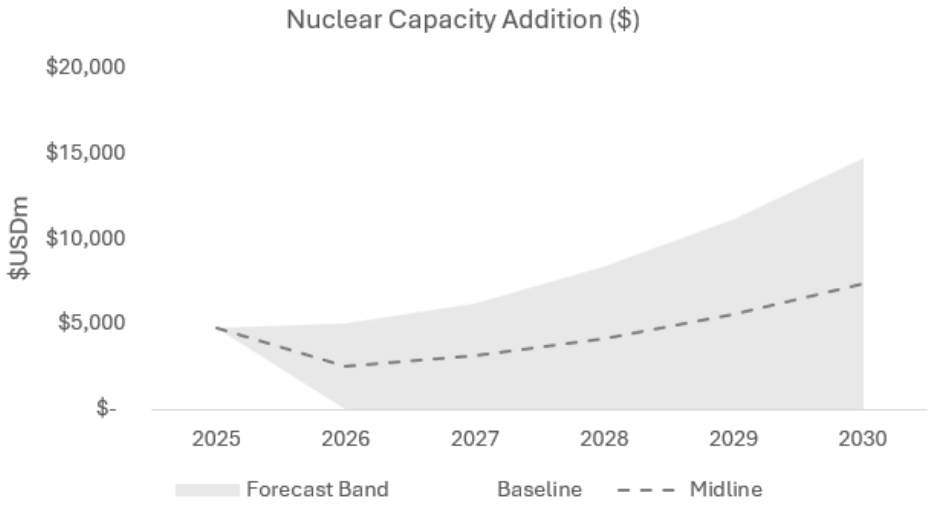
EIA projects zero nuclear additions before 2030. The GlobalData ceiling of about 1,500 MW is contingent on one or two projects clearing Nuclear Regulatory Commission licensing and financing on schedule; neither milestone has been reached. NuScale's US460 received NRC design approval in May 2025, the furthest any U.S. SMR has advanced, but design approval does not authorize construction or obligate funding[24]. No U.S. nuclear project holds a combined construction and operating license as of mid-2025; a project entering licensing today delivers in the late 2030s at the earliest.

Figure 20: Nuclear Capacity Additions: MSI Forecast, 2025–2030 (MW)



Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

Figure 21: Nuclear Construction Spend: MSI Forecast, 2025–2030 ($USD, millions)



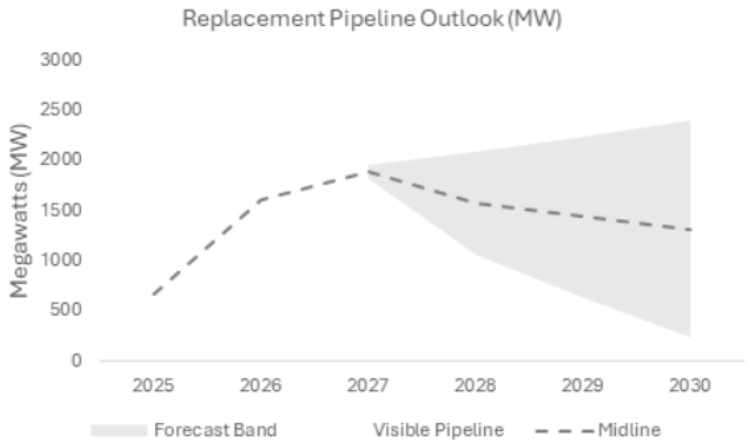
Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

At $9.5–10.0M per MW, nuclear costs six to seven times more than utility-scale solar and three times more than gas. The NuScale VOYGR project, cancelled in November 2023, saw projected costs rise from $3.6B to $9.3B before termination[25], a reminder of how quickly first-of-kind costs escalate. Nuclear does not influence the 2025–2030 cycle in volume terms, but as the only carbon-free source running continuously at 85–95% output, it is why data-center and advanced-manufacturing operators commit to decade-long development timelines.

4.4 REPLACEMENT VERSUS NEW-BUILD DEMAND

Replacement activity adds a secondary layer of demand that competes directly with new-build for labor and equipment. Gas-turbine repowering and plant modifications carry higher per-MW costs than new construction. Replacement volume rises to roughly 1,600 MW in 2026 and peaks near 1,900 MW in 2027, concurrent with the new-build surge, so both segments draw on the same electrical labor, transformers, and substation equipment at the same point in the cycle. Beyond 2027, replacement declines modestly while new-build keeps climbing, shifting dominance toward greenfield development.

Figure 22: Replacement Pipeline Outlook (MW), 2025–2030

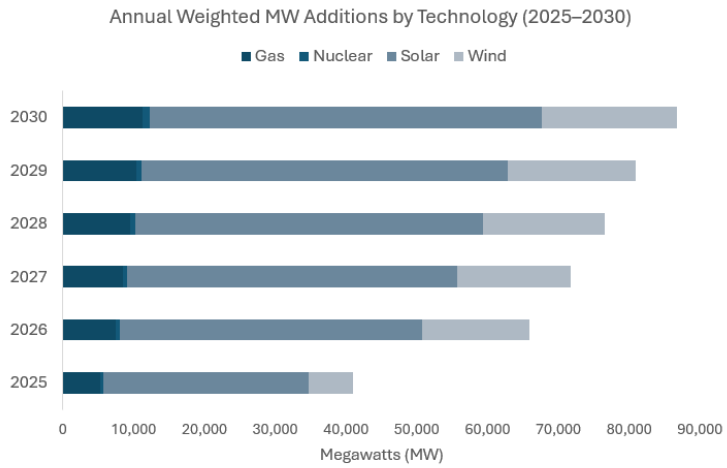


Source(s): GlobalData; MSI Economics.

4.5 TECHNOLOGY MIX

Solar holds the largest share every year, and its share of total additions rises from 71% in 2025 to about 74% by 2030 as the trimmed wind outlook leaves solar an even larger anchor. Wind roughly doubles over the period at the midline, but its outer-year path is highly uncertain. Gas grows by roughly three-quarters and holds near 11%, and nuclear stays at or below 1.2% throughout. The mix shift matters for EPC planning: the 2026 surge is solar- and wind-led, requiring panel-installation and turbine crews, while gas keeps growing in absolute volume after 2027, pulling demand toward combustion-turbine installation, civil works, and fuel systems. Contractors built around the 2026 solar surge will need different crews and equipment by 2029.

Figure 23: Technology Mix: Midline MW Additions by Technology, 2025–2030



Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

4.6 CONSTRUCTION-MARKET CAPITAL COST

This section translates the forecast into the construction market's addressable revenue: generation construction roughly doubles from about $70 billion in 2025 to about $150 billion a year by 2030, close to $691 billion of cumulative work over the period. The tables below present the midline of MSI's forecast and the associated construction-market impacts, decomposed into the EPC categories where that spend lands. Values are in 2025 nominal millions. Historical years (2022–2025) reflect spend on projects under construction in each year from 2026 baseline rather than the value of completed work, on the same active-construction basis used throughout the forecast.

Table 5: Natural Gas Capital Cost (Midline), $USD Million

Year	Civil / Struct.	Mech. Equip.	Elec. & I&C	Indirects	EPC (pre)	Fee & Cont.	Total EPC	Owner	Total Project
2025	$661	$5,869	$795	$2,190	$9,515	$999	$10,514	$2,103	$12,617
2026	$739	$6,561	$889	$2,448	$10,636	$1,117	$11,752	$2,350	$14,103
2027	$1,060	$9,418	$1,276	$3,514	$15,267	$1,603	$16,870	$3,374	$20,244
2028	$1,202	$10,680	$1,447	$3,984	$17,313	$1,818	$19,131	$3,826	$22,958
2029	$1,363	$12,110	$1,640	$4,518	$19,631	$2,061	$21,692	$4,339	$26,031
2030	$1,541	$13,693	$1,855	$5,108	$22,197	$2,331	$24,528	$4,906	$29,434

Natural gas follows a cyclical but supply-constrained path: a 2024 trough gives way to a steady climb to $29.4B by 2030 as turbine backlogs ease and deferred projects enter construction. Capital deployment occurs in waves tied to equipment delivery windows rather than demand variability.

Table 6: Nuclear Capital Cost (Midline), $USD Million

Year	Civil / Struct.	Mech. Equip.	Elec. & I&C	Indirects	EPC (pre)	Fee & Cont.	Total EPC	Owner	Total Project
2025	$689	$1,353	$251	$1,083	$3,376	$517	$3,893	$857	$4,750
2026	$366	$719	$133	$576	$1,795	$275	$2,070	$455	$2,525
2027	$452	$888	$165	$711	$2,216	$340	$2,556	$562	$3,118
2028	$603	$1,185	$220	$949	$2,956	$453	$3,409	$750	$4,159
2029	$805	$1,580	$293	$1,265	$3,943	$604	$4,547	$1,000	$5,548
2030	$1,065	$2,090	$387	$1,674	$5,217	$799	$6,016	$1,324	$7,340

Nuclear is lumpy and uncertain, reflecting the early-stage SMR market. The 2023–24 spike aligns with initial commitments; the subsequent drop-off underscores the absence of a continuous build cycle. The trajectory is option value more than steady growth, and commercial SMR traction could inflect it upward sharply.

Table 7: Solar Capital Cost (Midline), $USD Million

Year	Civil / Struct.	Mech. Equip.	Elec. & I&C	Indirects	EPC (pre)	Fee & Cont.	Total EPC	Owner	Total Project
2025	$6,901	$21,170	$5,366	$2,321	$35,759	$3,218	$38,977	$4,287	$43,264
2026	$9,772	$29,977	$7,598	$3,286	$50,633	$4,557	$55,190	$6,071	$61,261
2027	$11,112	$34,087	$8,640	$3,737	$57,576	$5,182	$62,757	$6,903	$69,661
2028	$13,082	$40,131	$10,172	$4,399	$67,784	$6,101	$73,885	$8,127	$82,012
2029	$13,826	$42,412	$10,750	$4,649	$71,637	$6,447	$78,085	$8,589	$86,674
2030	$14,439	$44,292	$11,227	$4,855	$74,813	$6,733	$81,546	$8,970	$90,516

Solar is the clearest sustained growth engine, expanding from $16.7B in 2022 to about $90B by 2030, driven by organic load growth and cost competitiveness more than incremental policy support. Battery-storage co-deployment adds cost but broadens applicability, reinforcing rather than dampening expansion.

Table 8: Wind Capital Cost (Midline), $USD Million

Year	Civil / Struct.	Mech. Equip.	Elec. & I&C	Indirects	EPC (pre)	Fee & Cont.	Total EPC	Owner	Total Project
2025	$1,186	$5,917	$1,285	$374	$8,761	$534	$9,295	$553	$9,848
2026	$2,345	$11,701	$2,540	$739	$17,325	$1,057	$18,382	$1,094	$19,476
2027	$1,775	$8,856	$1,923	$559	$13,113	$800	$13,913	$828	$14,741
2028	$2,129	$10,623	$2,306	$671	$15,729	$959	$16,688	$994	$17,682
2029	$2,432	$12,138	$2,635	$766	$17,972	$1,096	$19,068	$1,135	$20,203
2030	$2,747	$13,708	$2,976	$865	$20,297	$1,238	$21,535	$1,282	$22,817

Wind occupies a more modest but meaningful share. The 2022–24 decline reflects deferrals tied to permitting, cost inflation, and interconnection bottlenecks; a strong 2026 rebound lifts midline spend toward about $22.8B by 2030, though the outer-year path is highly uncertain, ranging from roughly $5.8B to $39.8B. Whether the recent disruption proves temporary or structural now depends heavily on how far the current administration delays installed and permitted projects.

Table 9: Weighted-Average Capital Cost of a Representative Plant (Midline), $USD Million

Year	Civil / Struct.	Mech. Equip.	Elec. & I&C	Indirects	EPC (pre)	Fee & Cont.	Total EPC	Owner	Total Project
2025	$4,567	$14,964	$3,633	$1,942	$25,106	$2,264	$27,370	$3,143	$30,513
2026	$6,734	$22,171	$5,421	$2,585	$36,911	$3,248	$40,158	$4,391	$44,549
2027	$7,638	$25,041	$6,093	$3,172	$41,944	$3,770	$45,714	$5,226	$50,940
2028	$8,995	$29,407	$7,169	$3,691	$49,262	$4,423	$53,686	$6,112	$59,798
2029	$9,299	$30,661	$7,434	$3,922	$51,317	$4,608	$55,924	$6,398	$62,323
2030	$9,479	$31,579	$7,605	$4,143	$52,806	$4,744	$57,550	$6,631	$64,181

Source(s): EIA Annual Energy Outlook 2026; GlobalData; MSI Economics.

CAPITAL-COST INTERPRETATION:

Table 9 above expresses a midline weighted-average cost for a single representative plant, not a market total. The aggregate market spend that profile underlies rises from $58.2B in 2022 to about $150.0B by 2030. The 2024–25 softness reflects overlapping turbine, wind, and nuclear transitions before a broad-based expansion. Demand is not the primary constraint; delivery is. For contractors, backlog visibility and equipment procurement (especially gas turbines) define revenue timing; for owners, the staggered gas profile makes early component reservation essential; for policymakers, this is an execution-capacity challenge requiring investment in supply chains, manufacturing throughput, and workforce.

4.7 LABOR, MATERIAL, AND EQUIPMENT DECOMPOSITION

The LME view reclassifies EPC cost (net of indirects) into labor, material, and equipment across the civil, mechanical, and electrical scopes. For contractors it is the operational map of the build: about 29% of construction cost is labor, 67.5% is material and permanent equipment, and 3.5% is construction equipment, so the resources to lock down are skilled crews and long-lead material, not demand. It also shows where supply-chain and labor pressure, and therefore pricing power, concentrate. Values are in 2025 nominal millions.

Table 10: Natural Gas LME (Midline), $USD Million

Year	Labor: 29.0%			Material: 67.5%			Equipment: 3.5%		
	Civil	Mech.	Elec.	Civil	Mech.	Elec.	Civil	Mech.	Elec.
2025	$191.62	$1,702.12	$230.58	$446.01	$3,961.84	$536.69	$23.13	$205.43	$27.83
2026	$214.18	$1,902.58	$257.73	$498.53	$4,428.42	$599.90	$25.85	$229.62	$31.11
2027	$307.46	$2,731.13	$369.97	$715.64	$6,356.94	$861.14	$37.11	$329.62	$44.65
2028	$348.67	$3,097.17	$419.56	$811.55	$7,208.94	$976.56	$42.08	$373.80	$50.64
2029	$395.34	$3,511.79	$475.72	$920.19	$8,173.99	$1,107.29	$47.71	$423.84	$57.42
2030	$447.02	$3,970.83	$537.91	$1,040.48	$9,242.46	$1,252.03	$53.95	$479.24	$64.92

Gas confirms that the binding constraint is upstream manufacturing capacity, most visible in mechanical equipment, not site labor. Labor and material demand expand in step with equipment releases rather than underlying project demand, producing a supply-driven cadence.

Table 11: Nuclear LME (Midline), $USD Million

Year	Labor: 29.0%			Material: 67.5%			Equipment: 3.5%		
	Civil	Mech.	Elec.	Civil	Mech.	Elec.	Civil	Mech.	Elec.
2025	$199.83	$392.35	$72.70	$465.11	$913.23	$169.22	$24.12	$47.35	$8.77
2026	$106.22	$208.56	$38.65	$247.24	$485.45	$89.95	$12.82	$25.17	$4.66
2027	$131.19	$257.58	$47.73	$305.35	$599.53	$111.09	$15.83	$31.09	$5.76
2028	$174.98	$343.56	$63.66	$407.27	$799.66	$148.17	$21.12	$41.46	$7.68
2029	$233.38	$458.23	$84.91	$543.22	$1,066.58	$197.63	$28.17	$55.30	$10.25
2030	$308.77	$606.24	$112.33	$718.68	$1,411.09	$261.47	$37.26	$73.17	$13.56

Nuclear leans on civil works, fabrication, and on-site assembly rather than a single constrained component. The limited equipment share reflects early-stage SMR standardization; greater modularization would shift cost toward factory-built systems. For now, scaling depends on proving repeatability in labor- and material-intensive processes.

Table 12: Solar LME (Midline), $USD Million

Year	Labor: 29.0%			Material: 67.5%			Equipment: 3.5%		
	Civil	Mech.	Elec.	Civil	Mech.	Elec.	Civil	Mech.	Elec.
2025	$2,001.41	$6,139.39	$1,556.18	$4,658.46	$14,289.95	$3,622.15	$241.55	$740.96	$187.82
2026	$2,833.96	$8,693.26	$2,203.53	$6,596.29	$20,234.31	$5,128.90	$342.03	$1,049.19	$265.94
2027	$3,222.51	$9,885.15	$2,505.64	$7,500.67	$23,008.53	$5,832.09	$388.92	$1,193.03	$302.40
2028	$3,793.89	$11,637.87	$2,949.91	$8,830.61	$27,088.14	$6,866.17	$457.88	$1,404.57	$356.02
2029	$4,009.56	$12,299.43	$3,117.60	$9,332.59	$28,627.98	$7,256.48	$483.91	$1,484.41	$376.26
2030	$4,187.28	$12,844.59	$3,255.78	$9,746.25	$29,896.89	$7,578.12	$505.36	$1,550.21	$392.94

Solar is material-heavy and highly scalable. Labor scales efficiently alongside deployment without the throughput constraints seen in gas or nuclear; battery-storage integration adds modest material and equipment layers but acts as an enabler rather than a brake.

Table 13: Wind LME (Midline), $USD Million

Year	Labor: 29.0%			Material: 67.5%			Equipment: 3.5%		
	Civil	Mech.	Elec.	Civil	Mech.	Elec.	Civil	Mech.	Elec.
2025	$343.84	$1,715.90	$372.53	$800.31	$3,993.92	$867.09	$41.50	$207.09	$44.96
2026	$679.97	$3,393.37	$736.71	$1,582.69	$7,898.35	$1,714.76	$82.07	$409.54	$88.91
2027	$514.65	$2,568.33	$557.59	$1,197.89	$5,978.01	$1,297.85	$62.11	$309.97	$67.30
2028	$617.32	$3,080.71	$668.83	$1,436.86	$7,170.62	$1,556.76	$74.50	$371.81	$80.72
2029	$705.34	$3,519.99	$764.20	$1,641.75	$8,193.07	$1,778.74	$85.13	$424.83	$92.23
2030	$796.61	$3,975.44	$863.08	$1,854.17	$9,253.17	$2,008.89	$96.14	$479.79	$104.16

Wind shows a hybrid dynamic where both materials and equipment matter but without the acute bottlenecks of gas. Turbine manufacturing remains a key driver, yet project timing is also shaped by site development, logistics, and installation. The post-2026 dip reflects the fading repowering wave; whether it proves temporary misalignment or a more structural limitation now hinges on how far new-build is delayed under current federal policy.

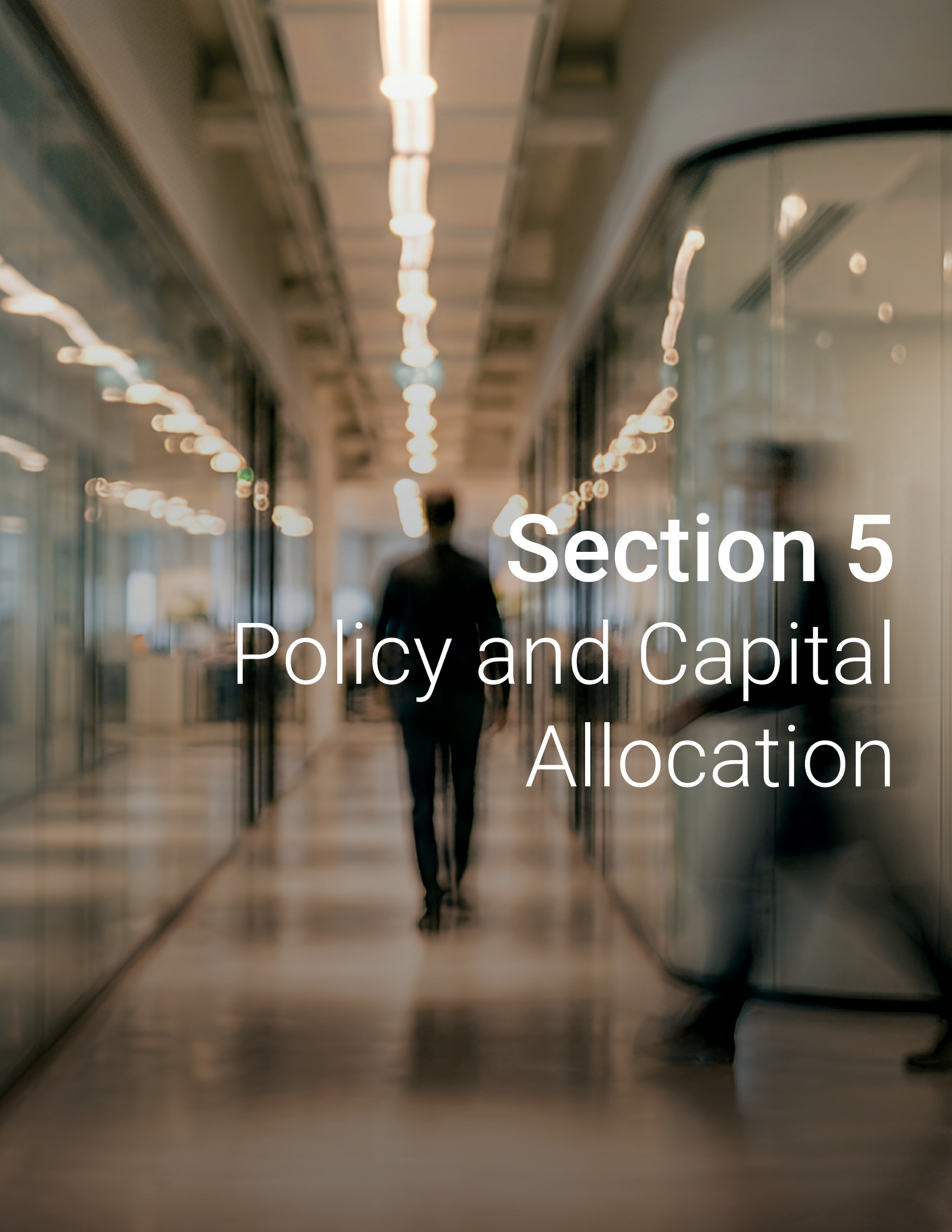
Table 14: Total Weighted LME (Midline), $USD Million

Year	Labor: 29.0%			Material: 67.5%			Equipment: 3.5%		
	Civil	Mech.	Elec.	Civil	Mech.	Elec.	Civil	Mech.	Elec.
2025	$2,262.18	$10,162.35	$2,036.97	$5,265.42	$23,653.75	$4,741.23	$273.02	$1,226.49	$245.84
2026	$3,125.13	$14,038.98	$2,814.01	$7,274.01	$32,676.93	$6,549.86	$377.17	$1,694.36	$339.62
2027	$3,458.90	$15,538.38	$3,114.56	$8,050.90	$36,166.92	$7,249.40	$417.45	$1,875.32	$375.89
2028	$4,070.23	$18,284.65	$3,665.03	$9,473.82	$42,559.11	$8,530.67	$491.24	$2,206.77	$442.33
2029	$4,444.00	$19,963.72	$4,001.59	$10,343.80	$46,467.28	$9,314.04	$536.35	$2,409.41	$482.95
2030	$4,817.94	$21,643.56	$4,338.30	$11,214.17	$50,377.26	$10,097.77	$581.48	$2,612.15	$523.59

Source(s): MSI Economics. Component shares: Labor 29.0%, Material 67.5%, Equipment 3.5%.

LME INTERPRETATION:

The market is overwhelmingly driven by material flows, with labor a substantial secondary component and equipment a targeted constraint in specific technologies. Even small equipment shares exert outsized influence on timing when components are specialized or capacity-limited, most acutely in gas and, to a lesser extent, wind. Targeted interventions in workforce development, domestic manufacturing, and supply-chain resilience relieve binding constraints more effectively than broad financial incentives. The next phase of expansion hinges on execution alignment across labor, materials, and equipment, with the tightest single category dictating how quickly capacity comes online.



Section 5
Policy and Capital Allocation

Federal policy actions in early 2026 have had an outsized effect on how capital is deployed across the power sector. Rather than broadly stimulating new supply, policy has reweighted capital toward dispatchable generation, curtailed certain technologies, and accelerated a shift toward privately financed, execution-driven development. The net effect is not more construction demand but a redistribution toward projects capable of navigating both regulatory and supply-side constraints.

5.1 REALLOCATION OF FEDERAL FINANCING

On January 22, 2026, the Department of Energy canceled approximately $30 billion of previously approved clean-energy loans and initiated revisions to an additional $53 billion within a $104 billion portfolio, while renaming the Loan Programs Office as the Office of Energy Dominance Financing[26]. The stated priority shift toward natural gas and nuclear is a material reorientation away from intermittent renewables.

The construction implications are large and asymmetric. Wind and solar projects that relied on federal credit support, particularly earlier-stage ones, face heightened financing uncertainty and elevated attrition risk; in some cases the federal government has moved to constrain or cancel renewable projects that did not rely on federal financing at all. Gas and nuclear are now positioned for greater support, but both are more capital-intensive and more equipment-constrained, limiting how quickly redirected capital becomes near-term volume. Even as backers raise large capital commitments across public and private markets, the pipeline of execution-ready projects remains hampered by the new policy framework.

5.2 OFFSHORE WIND AS A REMOVED CATEGORY

Federal intervention has effectively eliminated offshore wind from the 2026–2030 construction outlook. In March 2026, the Interior Department agreed to pay TotalEnergies $928 million to terminate two leases off New York and North Carolina, roughly 4 GW of potential capacity, with the associated capital redeployed into conventional energy, including LNG and upstream oil[27].

The action is not isolated. Permitting delays and stop-work orders have affected hundreds of wind and solar projects, with Vineyard Wind 1 among the most prominent suspended developments and measurable financial impacts on OEMs such as GE Vernova[28]. By contrast, terrestrial solar and, to a lesser extent, onshore wind remain comparatively resilient, particularly in Texas, which accounted for nearly a third of U.S. capacity additions in the first half of 2025. Smaller renewable projects that do not rely on federal financing or permitting fast-tracking are prevalent across the Great Plains and are likely to represent the bulk of new utility-scale generation in 2026[29]. Construction concentrates in technologies and regions least exposed to federal-intervention risk.

5.3 REDEFINING RESPONSIBILITY FOR GRID INVESTMENT

In March 2026, seven major technology firms signed the White House Ratepayer Protection Pledge, committing to absorb the cost of their own power infrastructure and prevent pass-through to residential ratepayers[30]. Similar commitments, including Anthropic's agreement to fully fund grid upgrades tied to its projects, reflect an emerging model in which large-load developers directly finance generation and transmission31. Implementation remains contingent on state-level regulatory approval; early attempts to formalize accelerated procurement, such as a proposed emergency PJM auction backed by long-duration data-center PPAs, have met institutional resistance[32]. For construction, the practical effect is an expansion of privately financed, vertically integrated development in high-growth load centers, where developers internalize infrastructure costs in exchange for schedule certainty.

5.4 CAPITAL MOVING UP THE STACK

Private capital has moved upstream, from financing end-use facilities to owning or controlling power supply. Institutional investors including Blackstone, Brookfield, and KKR are acquiring generation assets and entering joint ventures that integrate compute infrastructure with power delivery[33], illustrated by Blackstone's acquisition of the Potomac Energy Center and Brookfield's multi-billion-dollar distributed-generation commitments. In a supply-constrained environment, control over generation becomes a prerequisite for delivering end-use projects on schedule, and capital is willing to accept higher costs for reduced execution risk. For construction markets, this means a higher proportion of fully capitalized, execution-ready projects even as overall pipeline conversion stays constrained.

SOURCE(S)

[30] White House, "Ratepayer Protection Pledge," March 4, 2026.
[31] Anthropic public commitment on grid-upgrade cost coverage, February 11, 2026.
[32] Bloomberg / Utility Dive coverage of the January 2026 PJM emergency auction proposal.
[33] Commercial Property Executive, "Who's Funding the Data Center Boom?" March 4, 2026; PitchBook, Blackstone–Google joint venture coverage, May 2026; Bloom Energy 8-K (FY2026) on the Brookfield $5B partnership.
[34] Talen Energy press release and SEC 8-K, June 11, 2025; Utility Dive, June 11, 2025; FERC ruling on the co-located load arrangement, November 2024.

5.5 REGULATORY STRUCTURE AND MARKET DESIGN

Regulatory precedent continues to shape alternative delivery models. FERC's rejection of the proposed Amazon–Talen co-located arrangement at Susquehanna established a constraint on behind-the-meter configurations that bypass traditional interconnection[34], and subsequent structures have shifted toward front-of-the-meter arrangements. Behind-the-meter generation tied to large loads continues to be pursued by firms such as xAI and OpenAI, but its scalability depends on regulatory acceptance that remains uncertain, introducing a policy-dependent pathway for incremental capacity, especially where interconnection queues are constrained.

POLICY TAKEAWAY:

Near-term construction (2026–2027) remains governed by supply-side constraints, namely equipment and interconnection, regardless of capital availability. Medium-term conditions are more supportive as OEM production scales, long-duration PPAs mature, and private capital participation grows. Whether supply expands to meet demand or constraints throttle it depends on manufacturers' appetite for expansion (they have been burned by over-responding before) and on creative owner-led solutions such as behind-the-meter generation. The operative conclusion is positive but uncertain: discount any project lacking cleared interconnection, reserved equipment, and committed financing when translating pipeline figures into realizable volume.



SOURCE(S)

[30] White House, "Ratepayer Protection Pledge," March 4, 2026.
[31] Anthropic public commitment on grid-upgrade cost coverage, February 11, 2026.
[32] Bloomberg / Utility Dive coverage of the January 2026 PJM emergency auction proposal.
[33] Commercial Property Executive, "Who's Funding the Data Center Boom?" March 4, 2026; PitchBook, Blackstone–Google joint venture coverage, May 2026; Bloom Energy 8-K (FY2026) on the Brookfield $5B partnership.
[34] Talen Energy press release and SEC 8-K, June 11, 2025; Utility Dive, June 11, 2025; FERC ruling on the co-located load arrangement, November 2024.



Section 6
Technology Pathways and Optionality

Technology choice does not relieve near-term construction constraints; it shifts how demand is composed and which resource pools it draws on. Battery storage, hydrogen-capable turbines, and small modular reactors each operate on a distinct horizon. Those with significant volume through 2027 fit within existing supply chains; those with the best long-term demand fit cannot clear licensing or financing within the forecast window.

Table 15: Technology Demand-Fit and Construction Impact, 2025–2030

	Battery Storage (BESS)	Hydrogen-Capable Turbines	Small Modular Reactors
Planning horizon	2025–2030	2025–2030	2030s
Demand fit	Medium	Medium	High
2030 capacity additions	High	Low	Low
Commercial readiness	High	High turbine / Low fuel	Low
Capital cost vs. gas	~1x	~1x	4–8x
Binding constraint	FEOC compliance	Hydrogen production economics	Licensing / FOAK capital cost

Source(s): Demand fit: match to continuous baseload at 85–95% capacity factor. Construction volume: High >10,000 MW, Medium 2,000–10,000 MW, Low <2,000 MW (2030 midline). Capital cost: overnight $/kW relative to combined-cycle gas at ~$1,100/kW.

6.1 BATTERY STORAGE: NEAR-TERM VOLUME, CONCENTRATED EXECUTION PRESSURE

Battery energy storage (BESS) is the only technology in this group with material near-term volume. Planned additions reach 24.3 GW in 2026, a 62% year-over-year increase that raises installed capacity from 44.6 GW to roughly 68.9 GW in a single year. More than half of 2026 additions concentrate in Texas, with most of the remainder in California and Arizona, and about 48% of storage is co-located with solar. Battery, solar, and gas construction therefore converge in the same markets and window, competing for the same electrical labor, interconnection capacity, and transformers.[35]

Sourcing rules also tighten across the window. Under Section 48E, the material-assistance cost ratio that storage projects must source from non-prohibited foreign entities rises from 55% for construction beginning in 2026 to 75% by 2030, while the domestic-content bonus threshold steps up on a parallel graduated schedule[36]. Both tighten as volume peaks, adding sourcing risk for projects that locked in supply before the thresholds took effect. Labor, interconnection, and transformer availability, not demand, will determine how much of the 2026 target is delivered on schedule.

6.2 HYDROGEN-CAPABLE TURBINES: PROCUREMENT WITHOUT NEAR-TERM EXPANSION

Hydrogen-capable gas turbines affect construction through equipment specification, not a distinct build cycle. Commercially available turbines accommodate 30–50% hydrogen blending; smaller aeroderivative units can run on 100% hydrogen, though full-scale heavy-duty deployment remains in development[37]. The constraint is fuel, not hardware: policy changes since October 2025, including withdrawal of roughly $2.2B in hydrogen-hub infrastructure funding[38], make cost-competitive hydrogen supply unlikely within the forecast window. Projects specifying hydrogen-ready turbines are locking in equipment flexibility for a fuel that cannot yet be delivered economically; the underlying construction work is conventional gas, drawing on the same labor, equipment, and procurement channels.

6.3 SMALL MODULAR REACTORS: STRATEGIC POSITIONING BEYOND THE WINDOW

SMRs generate continuous, carbon-free power at the output data centers and advanced manufacturing require, but licensing timelines and capital cost put construction outside the 2025–2030 window. The NRC finalized a new licensing framework for advanced reactors in April 2026 (10 CFR Part 53), its first new reactor-licensing regulations since 1989[39]. No project submitting under Part 53 is expected to reach construction approval before 2030; U.S. nuclear activity through 2030 is limited to site preparation, engineering, and restart work at existing facilities.

Table 16: SMR and Reference Technology Capital Costs

Technology	Overnight Capital ($/kW)	LCOE ($/MWh)
SMR range (design estimates)	$3,985–$4,844	$80–90
Boiling-water SMR (estimated)	$10,667–$18,667	
Combined-cycle gas (2030)	$1,083	$35–55
Utility solar PV (2030)	$1,041	$30–50

Source(s): Vegel et al. 2023; OPG FID May 2025; NREL ATB 2024.

Estimated capital costs run from roughly $4,000/kW for early-stage designs to $18,000/kW for first-of-a-kind units[40], against roughly $1,100/kW for combined-cycle gas[41]. Any near-term forecast that includes SMR construction volume is pricing work that has not cleared licensing or financing.

6.4 RELIEF PATHWAYS AND SUBSTITUTION

Faster-delivery options compress individual project timelines but do not remove the shared constraints on transformers, labor, and interconnection. The assessment below combines four factors: equipment lead time, strength of the demand-side or OEM capex signal, federal policy posture, and binding contracts. High indicates equipment is likely deliverable inside the window with committed capital and neutral-to-favorable policy; Medium indicates material friction in one input or contracted volume that ramps several years out; Low indicates lead times or regulatory and execution risk that remain unresolved near-term.

Table 17: Near-Term Supply Feasibility by Relief Pathway

Pathway	Lead Time	Capex Signal	Near-Term Feasibility
Aeroderivative gas	18–24 mo	Strong (GE / Siemens / MHI scaling)	High
Solid-oxide fuel cells	90 days–12 mo	Growing ($7.65B closed Oct '25–Jan '26)	Medium
Utility-scale solar + storage	<12 mo modules	Mixed (DOE pullback; private capital steady)	High in TX / AZ / CA
Existing-fleet nuclear PPAs	Contracted; ramp 2026–32	Strong (Talen, Vistra, Constellation)	Medium (financing now, MW later)
Heavy-frame combined-cycle gas	5–7 yr	Strong (200+ GW OEM guidance)	Low 2026–28; High 2029–30
Nuclear restart (Three Mile Island)	Target 2027	Strong (Microsoft–Constellation)	Medium (regulatory + execution risk)

Source(s): Utility Dive, March 2026; Bloom Energy FY2026 8-K; SEIA, March 2026; NucNet, November 2025.

Aeroderivative turbines deliver in 18–24 months against five to seven years for heavy-frame units and are increasingly installed at or near the facility they serve, bypassing portions of the regional interconnection queue[42]. Solid-oxide fuel cells deploy in 90 days to 12 months, with $7.65B in private capital closed between October 2025 and January 2026, though scaling feasibility remains uncertain[43]. Utility-scale solar and storage in Texas, California, and Arizona executed on or ahead of schedule through Q3 2025 before a sharp Q4 pullback as One Big Beautiful Bill Act deadlines disrupted year-end completion[44]. Nuclear restarts require sustained regulatory support but have drawn positive signals from the current administration.

TECHNOLOGY TAKEAWAY:

Near-term volume consists of storage, solar, and conventional gas builds; alternatives contribute little to the mix before 2030. Hydrogen-capable turbines and SMRs shape equipment specification and capital positioning today but add no construction volume in the window. Technology choice determines the composition of demand, not its ceiling.

SOURCE(S)

[35] U.S. Energy Information Administration, Preliminary Monthly Electric Generator Inventory (December 2025) and Electric Power Monthly (February 2026).
[36] One Big Beautiful Bill Act amendments to Internal Revenue Code Section 48E governing energy storage technology: the material-assistance (prohibited foreign entity) cost-ratio threshold rises from 55% for construction beginning in 2026 to 75% for 2030 and later, alongside a graduated domestic-content bonus schedule. See IRS, Domestic Content Bonus Credit guidance, 2024–202
[37] GE Vernova, H-Class Gas Turbines.
[38] U.S. Department of Energy, termination of hydrogen-hub awards for ARCHES (California) and the Pacific Northwest Hydrogen Hub, October 3, 2025 (E&E News).
[39] Nuclear Regulatory Commission, Part 53 — Risk-Informed, Technology-Inclusive Regulatory Framework for Commercial Nuclear Plants. Effective April 29, 2026.
[40] Vegel et al., "Techno-economic analysis of advanced small modular nuclear reactors." Applied Energy, 2023; UAMPS/NuScale joint statement, November 2023 (E&E News).
[41] Ontario Power Generation, Darlington Small Modular Reactor Project.
[42] Utility Dive, "5-year waits and rising costs: how demand is redefining the gas turbine market." March 2026.
[43] Bloom Energy 8-K (FY2026); Bloom–Oracle and Bloom–AEP agreements (October 2025–April 2026); Commercial Property Executive (March 4, 2026); PitchBook (May 2026).
[44] SEIA, Solar Market Insight Report Q4 2025. March 2026.



Section 7
Implications and Outlook

Across demand, supply, forecast, policy, and technology, one conclusion holds: the U.S. power-construction market is large and growing, but its near-term shape is set by deliverability rather than demand. The following implications consolidate the analysis.

7.1 THE 2026 SURGE IS THE PLANNING HORIZON THAT MATTERS

Volume jumps sharply in 2026, roughly 40% in the EIA baseline and around 50% at the midline, and remains elevated in MSI Economics' forecast scenario to 2030. Interconnection approvals, equipment slots, and craft-labor commitments for 2026 starts needed to be in place by late 2024, a window that has largely closed for firms that have not already acted. The 2026–2027 overlap of new-build and replacement activity is the tightest point in the cycle: solar and wind repowering, gas new-build, and replacement modifications peak simultaneously and compete for the same electrical labor, transformers, and substation equipment.

7.2 GAS BECOMES THE CRITICAL DISPATCHABLE ADDITION AFTER 2027

The 2026 surge is solar- and wind-led. After 2027, solar remains the volume leader, but gas is the dispatchable source that keeps scaling, and the build shifts toward gas-related work even as gas holds near 11% of total additions. Firms oriented exclusively toward solar EPC face a composition mismatch as that shift arrives. Equipment procurement for post-2027 gas construction requires commitments in 2025–2026, since combustion-turbine lead times run 36–48 months, as opposed to the 5-7 years to full operation. Contractors built around the 2026 solar surge will need different crews and equipment by 2029.

7.3 OUTER-YEAR VOLUME IS CONTINGENT, NOT COMMITTED

The roughly $61B spread between the EIA floor and GlobalData ceiling by 2030 is not committed work; it is announced volume that has not cleared interconnection, financing, or equipment procurement. Through 2026, volume is largely confirmed; beyond that, outcomes depend on conversion. Any project lacking cleared interconnection, an executed agreement, reserved equipment, and committed financing should be materially discounted when translating pipeline figures into realizable construction.

7.4 WHAT TO WATCH

• **Equipment throughput.** Whether transformer, switchgear, and turbine capacity expansions come online on the 2027–2028 schedule manufacturers have guided, and whether GOES supply, which has seen no announced expansion, becomes the residual bottleneck.

• **Policy stability.** Whether the early-2026 reorientation toward gas and nuclear holds, and how state regulators respond to developer-funded grid models and behind-the-meter configurations.

• **Conversion rates.** Whether the deferred GlobalData pipeline converts into construction from 2028 or slips further, which determines whether the late-decade volume base materializes.

OUTLOOK:

The constraint through 2030 is execution, not demand. Supply-chain limits are binding through 2027 for projects without secured equipment and execution pathways, and become manageable from 2028 as manufacturing capacity, accumulated demand, and established financing structures support a broader release of work. Volume is deferred, not destroyed, and timing, queue progression, and execution readiness, not the scale of what is announced, determine when demand becomes construction.



Appendix I
Methodology

The primary approach decomposes total project cost into standard EPC cost components, allowing generation investment to be mapped directly into construction market categories. At a project level:

$$\text{Total Project Cost} = \text{EPC}_{direct} + \text{Indirects} + \text{Fee/Contingency} + \text{Owner Costs}$$

WHERE

$$\text{EPC}_{direct} = C_{civil} + C_{mech} + C_{electrical}$$

This structure is built from the following elements:

- **Civil, structural, and installation**
- **Mechanical equipment and installation**
- **Electrical and I&C supply and installation**
- **Project indirects**
- **EPC cost (pre-fee and contingency)**
- **Fee and contingency**
- **Owner costs (excluding financing)**

This method isolates construction-relevant spend, excluding financing, and aligns directly with contractor scope and procurement categories.

The cost shares are benchmarked to the EIA's Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants[45] and converted into percentage allocations. These shares were escalated from 2013 to a 2025 baseline using the Turner Construction Cost Index:

$$C_{2025} = C_{2013} \times (1 + 0.719)$$

While absolute costs are adjusted, component percentages are held constant to preserve structural consistency across technologies. These percentages are then applied to the midline capital forecast by technology, ensuring alignment with the capacity model.

METHODOLOGICAL STRUCTURE OF CAPITAL COST ROLL-UP

The cost structure is organized as a hierarchical build-up from direct construction inputs to total project cost, reflecting how capital flows through engineering, procurement, and construction (EPC) execution. The individual dollar values vary by technology and project, but the accounting relationships are fixed and form the basis for consistent cost translation across the forecast.

Step 1: Direct and Indirect EPC Costs
At the base level, construction costs are decomposed into three primary direct scopes: civil, mechanical, and electrical, augmented by project-level indirects. These components collectively define the core EPC scope prior to risk adjustment:

$$\text{EPC}_{pre} = C_{civil} + C_{mechanical} + C_{electrical} + C_{indirect}$$

WHERE:

- C_{civil}: Civil, structural, and site installation scope
- $C_{mechanical}$: Major equipment supply and mechanical installation
- $C_{electrical}$: Electrical systems and instrumentation & control (I&C)
- $C_{indirect}$: Construction management, temporary facilities, engineering support, and other overhead

This aggregation represents the fully specified construction scope under expected conditions, but excludes allowances for uncertainty, contractor margin, and execution risk.

SOURCE(S)

[45] U.S. Energy Information Administration. Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies. Prepared by Sargent & Lundy for AEO2025. February 2025. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

Step 2: Risk Adjustment and Commercial Terms
To convert base EPC costs into a deliverable contract value, fee and contingency are applied:

$$\text{EPC}_{total} = \text{EPC}_{pre} + C_{contingency} + C_{fee}$$

These components serve distinct functions:

- Contingency accounts for design incompleteness, field conditions, and execution uncertainty
- Fee reflects contractor margin and commercial structure

The result is Total Project EPC, which represents the fully burdened construction contract value and the portion of total cost most directly tied to contractor activity.

Step 3: Owner Costs and Total Project Value
Finally, EPC costs are combined with owner-incurred expenses to arrive at total project cost:

$$\text{Total Project Cost} = \text{EPC}_{total} + C_{owner}$$

Where C_{owner} includes:

- Development and permitting costs
- Owner's engineering and project management
- Interconnection, land acquisition, and administrative costs

Structural Interpretation
This formulation establishes a consistent cost hierarchy:

$$\underbrace{C_{civil} + C_{mechanical} + C_{electrical} + C_{indirect}}_{\text{EPC}_{pre}} \rightarrow \underbrace{\text{EPC}_{pre} + \text{contingency} + \text{fee}}_{\text{Total EPC}} \rightarrow \underbrace{\text{Total EPC} + \text{owner costs}}_{\text{Total Project Cost}}$$

Each layer represents a progressive widening of scope:

- EPC_{pre} = technical construction requirements
- Total EPC = executable contract value under risk and commercial terms
- Total Project Cost = full capital commitment excluding financing

Application to the Forecast
Within the MSI framework, this structure allows total project capital to be systematically decomposed into construction-relevant categories. While absolute dollar values differ by technology, the proportional relationships between these layers are preserved, enabling consistent application across the capacity forecast.

The practical implication is that construction market impacts are driven primarily by the EPC layers, while owner costs provide context for total capital scale but are less directly tied to labor and equipment demand.
These categories are applied only to projects under construction in a given year, so historical totals capture spend on work active that year rather than the value of completed projects, and forecast years capture spend still to be deployed. This is the same active-construction basis used throughout the report.

Brandon Michalski
Principal, Chief Economist
MSI Economics
MOCA Systems, Inc.

